CURRENT AND HISTORICAL OIL AND GAS TENURE LEGISLATION IN ALBERTA

Working Paper

Alberta
ENERGY AND
NATURAL RESOURCES
Mineral Resources Division

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Current and Historical Oil and Gas Tenure Legislation in Alberta is a working paper circulated for purposes of review.

FOREWORD

This working paper provides an overview of the development of the Province of Alberta's oil and gas legislation and tenure systems. The period covered is from 1930, when the province assumed control of its energy and other resources, through 1983. The overview covers the historical evolution of the legislation and regulations which govern the present tenure system.

The Alberta Department of Energy and Natural Resources is responsible for the management and administration of Alberta's natural resources. The department is divided into two sectors: energy resources, which is responsible for energy and other mineral resources, and renewable resources, with responsibilities for public lands, forests, fish and wildlife.

The major objective of the Alberta Department of Energy and Natural Resources is to manage Alberta's natural resources in a manner which ensures their efficient development for the greatest possible benefit to the province and its people. To assist in the achievement of this objective, the Government of Alberta has enacted legislation governing its constantly evolving tenure system for oil and gas and other minerals. This legislation is supported by complementary policies which govern the management and administration of the natural resources.

The Mineral Resources Division, within the energy resources sector of the department, is made up of the Exploration Branch, the Minerals Support Branch, the Mineral Agreements Branch and the Oil and Gas Agreements Branch. Alberta's oil and gas agreements are managed by the Oil and Gas Agreements Branch.

TABLE OF CONTENTS

		Page
1.	INTRODUCTION	1
2.	PAST OIL AND GAS RIGHTS TENURE SYSTEMS	3
	2.1 Prospecting Permits and Petroleum and Natural Gas Leases	3
	2.2 Petroleum and Natural Gas Reservations	5
	2.3 Provincial Reserves	7
	2.4 Mines and Minerals Act	8
	2.5 Natural Gas Licences and Leases	8
	2.6 Crown Reserve Natural Gas Licences	9
	2.7 Crown Reserve Drilling Reservations	10
	2.8 Petroleum and Natural Gas Permits	11
	2.9 Significant Historical Events between 1970 and 1976	12
3.	PRESENT OIL AND GAS RIGHTS TENURE SYSTEM	15
	3.1 Acquisition of Oil and Gas Rights	16
	3.1.1 Public Sales	17
	3.1.2 Private Sales	22
	3.2 Petroleum and Natural Gas Licences	22
	3.3 Petroleum and Natural Gas Leases	26
	3.3.1 Lease Continuation	31
	3.3.2 Offset Obligations	41
	3.3.3 Unitization	44
4.	GEOPHYSICAL EXPLORATION	47
5.	INCENTIVE PROGRAMS	51
	5.1 Exploratory Drilling Incentive System (EDIS)	51
	5.2 Geophysical Incentive System (GIS)	59
6.	REFERENCES TO LEGISLATION	65

LIST OF TABLES

		Page
1.	Schedule B of the Petroleum and Natural Gas Licence Regulations	25
2.	Schedule B of the Petroleum and Natural Gas Lease Regulations	30
3.	Schedule N of the Exploratory Drilling Incentive Regulations, Class A Interval	53
4.	Schedule O of the Exploratory Drilling Incentive Regulations, Class B Interval	55
5.	Schedule B of the Geophysical Incentive Regulation, 1981 . .	61

LIST OF FIGURES

		Page
1.	Lease Selection from a Petroleum and Natural Gas Reservation	6
2.	Two Categories of Zones Available for Disposition	19
3.	Other Categories of Zones Available for Disposition	20
4.	Combination of Zones Available	21
5.	Petroleum and Natural Gas Licences Area Map	24
6.	Potential Lease Selection in Northern Area	27
7.	Expiring Lease with Productive Well	33
8.	Case 1: Expiring Lease with Shallow Probably-Productive Lands	35
9.	Case 2: Expiring Lease with Deep Probably-Productive Lands	36
10.	Case 1: Lease Review Following Special Continuation Period	38
11.	Case 2: Lease Review Following Special Continuation Period (One Well Drilled)	39
12.	Case 3: Lease Review Following Special Continuation Period (Two Wells Drilled)	40
13.	Lease Subject to Six-Month Productivity Notice	42
14.	Lease Subject to One-Year Productivity Notice	43
15.	Provincial Land Classifications	48
16.	Exploratory Drilling Incentive Credit Areas	57
17.	Determination of Class A and Class B Intervals under the 1983 Drilling Incentive Regulation	58
18.	Geophysical Incentive Program Areas of the Province	62

1. INTRODUCTION

The mineral rights in approximately 81 per cent of the province's 66 million hectares are held by the Alberta Crown and administered by the Government of Alberta. The remaining mineral rights are held by the federal Crown within the national parks and Indian reserves and by the Hudson's Bay Company, the national railway companies and the original homesteaders through rights granted by the federal Crown before 1887.

The orderly management and development of the province's oil and gas and other mineral rights is essential to the viability of the petroleum industry and the provincial economy. It is important that an acceptable return be realized both by the petroleum industry and by the people of Alberta. In the development of these non-renewable resources the renewable resource base cannot be unduly compromised.

The petroleum industry requires sound government legislation and policies for systematic exploration and development. To accomplish this objective, the Alberta government has over the years introduced innovative legislation.

Alberta's oil and gas legislation has progressed through three major steps. The first step was moving from small prospect-staking (768 hectares) to the creation of large reservations (20 000 hectares). These reservations were created where little or no drilling had taken place. The main tenure feature of a reservation was that one-half of the acreage had to be returned to the Alberta Crown.

The second major step was taken in order to stimulate the exploration of natural gas which was marginally economic to produce at the

time. Upon the discovery of natural gas and completion of a continous drilling program, to prove up the extent of the discovered natural gas reservoir, large blocks of acreage could be held.

The third major step was the severance of the deeper non-productive zones below producing zones and shorter-term exploration agreements and leases. Only by drilling could parties earn development leases.

This working paper summarizes the innovative legislation and policies implemented through each of the three steps. Each step was introduced as the needs of a particular time were identified. Legislation was implemented to assist in the creation of a stable investment climate for the petroleum industry, at the same time striking a delicate balance in the protection of a depleting resource.

2. PAST OIL AND GAS RIGHTS TENURE SYSTEMS

Alberta's mineral rights were owned by the federal Crown and administered by the Government of Canada's Department of the Interior before their transfer, October 30, 1930, to the Alberta Crown.

The statutes and regulations of the Government of Canada pertaining to the natural resources in the province were continued by The Administration of Natural Resources (Temporary) Act. This act was in effect and administered by Alberta's Department of Lands and Mines until June 18, 1931, when the Provincial Lands Act and associated regulations came into force. These regulations were almost identical to the regulations in force before October, 1930.

The legislation and land tenure systems which were in place before 1976 are described in chronological order as follows.

2.1 Prospecting Permits and Petroleum and Natural Gas Leases

In 1931, the regulations governing the issuance of Permits to Prospect for Petroleum and Natural Gas and the Petroleum and Natural Gas Regulations were promulgated under the Provincial Lands Act. Prospecting permits were granted by the Department of Lands and Mines for a term of one year on a maximum area of 768 hectares. The permittee was required to conduct core drilling on the permit, thus earning the entire lease. Twenty-one-year petroleum and natural gas leases were granted over a maximum of 768 hectares. These leases were renewable for a further 21 years, provided the core drilling requirements were met.

Once a lease was granted, a lessee was required to install

machinery suitable for carrying on prospecting[1] operations within one year of the lease date. The value of the machinery installed did not have to exceed $5,000. The lessee was also required to commence the drilling of a well within 15 months of the lease date. The regulations allowed the grouping[2] of leases. Grouping satisfied the drilling requirements for all leases in the group if a well was drilled on one of the grouped leases. The maximum area permitted in a group was 8000 hectares. Rentals which were established in 1920, at the rate of $1.25 a hectare for the first year and $2.50 a hectare for subsequent years, did not change.

By 1936, there were great advancements in geological knowledge and geophysical techniques for locating new oil and gas bearing geological structures. As a result, it became apparent that prospecting permits were too small in size to provide a development program on their own. Consequently, the regulations governing the issuance of prospecting permits were amended, allowing the size of a permit to be at the discretion of the department.

The Petroleum and Natural Gas Regulations were also amended in 1936 to increase from 8000 to 20 000 hectares the maximum size of allowed lease groupings. The lessee was also permitted to use the expenditure amounts incurred in drilling to act as a credit toward satisfying the lease rentals up to and including the twelfth year of the lease.

In August, 1941, new Petroleum and Natural Gas Lease Regulations governing the disposal of oil and gas rights were established, increasing the area obtainable under lease to 3840 hectares from 768 hectares.

[1] The term prospecting used to denote exploration as it is known today.

[2] The consolidation of leases for operating purposes so that exploration work such as drilling is conducted on one or more grouped leases, disregarding the lease boundaries.

2.2 Petroleum and Natural Gas Reservations

The prospecting permit regulations were rescinded in 1937 and replaced by regulations governing a new form of disposition called the Petroleum and Natural Gas Reservation. Up to 20 000 hectares could be included in a reservation, thereby allowing exploration to take place over large areas where little was known about the hydrocarbon potential.

Reservations were available through competitive bid. This involved advertising the area available through a "posting notice" which was posted in the Mining Recorder's Office. A sale date was named and all parties interested could submit a sealed bid to the office together with the full amount of the tendering bid. When no bid for a reservation was received, it became available the day following the sale on a first-come, first-served basis for a minimum filing fee.

The principle of grouping was carried over from the prospecting permit. It was recognized that where a company held several reservations, a more beneficial exploration effort could be obtained by concentrating exploration work on one or several of the reservations, rather than all simultaneously. A maximum of 80 000 hectares of reservation area could be grouped.

A highly significant change introduced at this time was that 50 per cent of a reservation's area reverted to the Alberta Crown at the expiry of the reservation term. This reverted area was called Crown reserve. When a reservation holder prepared his lease selection there were specific rules as to the configuration of the area which could be selected. Individual leases selected out of reservations could not exceed 4.8 by 4.8 kilometres or 6.4 by 6.4 kilometres. The blocks selected had to be in a checkerboard pattern or separated by a corridor of one mile (Figure 1). A reservation could comprise several townships in area (a township comprises 36 sections), but only 50 per

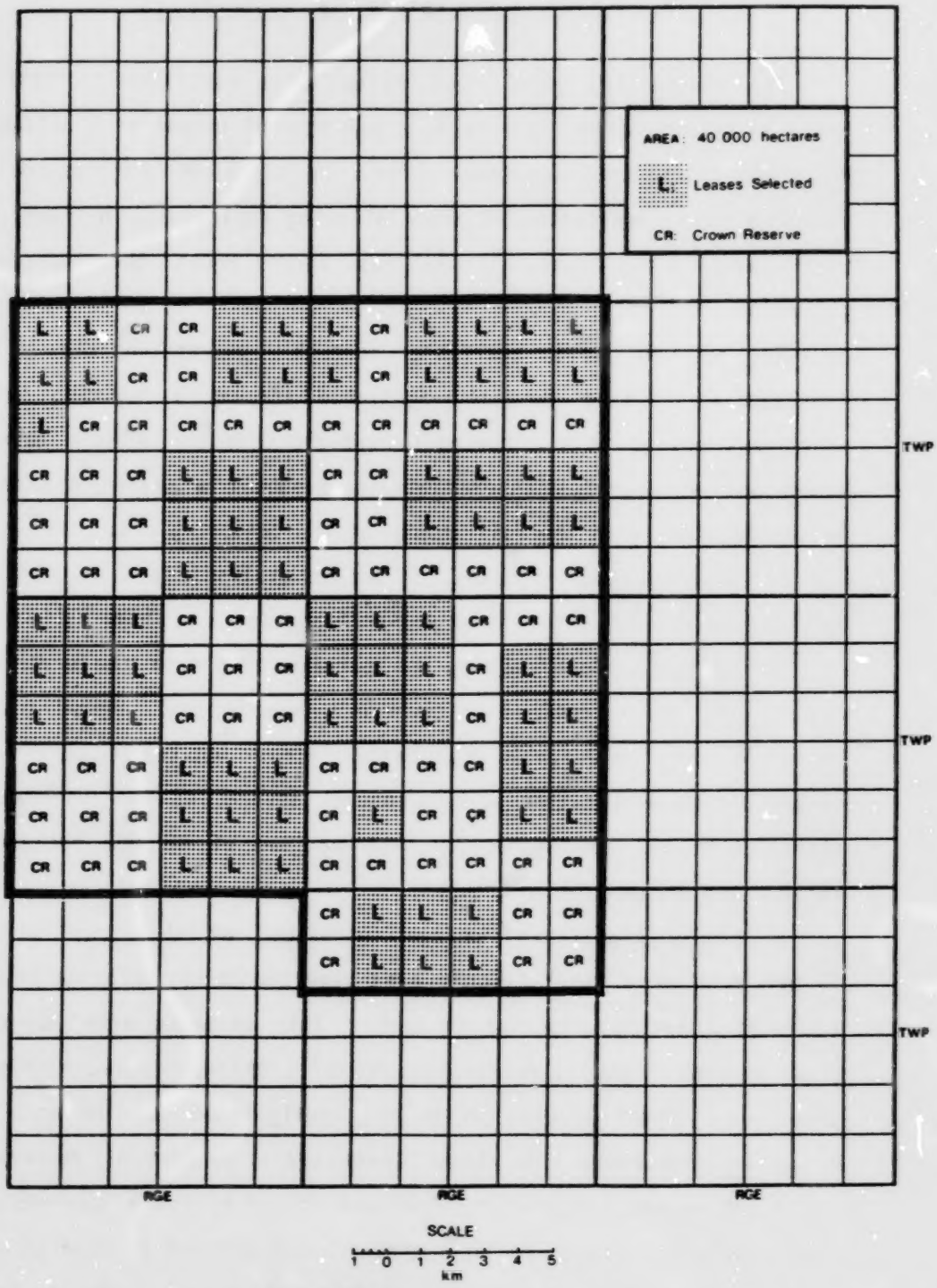


Figure 1. Lease selection from a petroleum and natural gas reservation

cent of a reservation's area in each township could be selected as lease. The acreage between the selected lease blocks was designated a Crown reserve.

The size and pattern of the lease blocks was designed to ensure that a company discovering a hydrocarbon-bearing pool would be forced to return part of the discovered pool to the Crown. Subsequently, the reverted area was made available to other petroleum industry members for further development on a competitive basis.

An oil discovery immediately created an obligation on the reservation holder to make a lease selection around the discovery, with half of the area reverting to the Crown. Once the reservation holder had selected his lease area and the Crown reserve had been determined, those lands were withdrawn from the reservation. The balance of the reservation was permitted to continue for the purpose of conducting further exploration work.

The petroleum and natural gas reservation established in the 1937 regulations remained in effect until December, 1982, when the last issued reservation was cancelled in the department's records. In 1949 and later in 1962 amended regulations governing reservations were promulgated but only contained minor changes to the original reservation form of disposition.

2.3 Provincial Reserves

It was recognized in 1941 that a higher degree of control over the disposition of mineral rights was required in a number of selected areas throughout the province. Fifteen of these areas were established by legislation and were withdrawn from disposition under the normal lease and reservation regulations.

In 1944, regulations were enacted governing the disposition of Crown reserves, previously established provincial reserves, and

reserves selected from petroleum and natural gas reservations. A significant feature of these regulations was that 100 per cent of the area within the selected provincial reserves was declared to be Crown reserve. This is in contrast to 50 per cent of the area granted in reservations outside these reserves in the rest of the province. As a result, the Crown reserved the right to reject any bids on petroleum and natural gas reservations within the provincial reserves, and the practice of filing the day following a sale was not permitted.

2.4 Mines and Minerals Act

The Mines and Minerals Act came into effect April 1, 1949, and applied to all Alberta Crown petroleum and natural gas rights formerly governed by the Provincial Lands Act.

With the establishment of the Mines and Minerals Act, the Alberta Department of Lands and Mines was succeeded by two departments: the Department of Mines and Minerals, responsible for the administration of non-renewable resources, and the Department of Lands and Forests with similar responsibilities for renewable resources.

2.5 Natural Gas Licences and Leases

[1]* The Natural Gas Licence Regulations introduced in 1951 created the natural gas licence form of agreement. The natural gas licence granted the option to the petroleum and natural gas reservation holder, upon discovery of natural gas, of earning a substantial amount of the natural gas rights underlying his reservation.

The area to be selected as natural gas licence had to be contiguous;[3] the lease block and Crown reserve corridor requirement

* Numbers in brackets cite the regulations currently in effect. See Section 6 for references.

[3] All lands had to be in actual contact and no corridors or space could be left between selected lands.

were waived but the maximum size of the licence could not exceed 36 sections.

During the term of the natural gas licence, renewable for two and a half years, the licensee was required to carry out a continuous drilling program commencing within three months of the issuance of the licence. The licences were zone specific.[4] If further drilling discovered natural gas in paying quantities in a zone other than that contained in the licence, the discovered zone could be included in the original licence.

The natural gas lease, introduced in 1952, allowed holders of natural gas licences to earn 21-year natural gas leases while undertaking a continuous drilling program. This lease-earning drilling program was intended to determine the area encompassed by the natural gas pool in a licence. The natural gas lease was confined to the zone(s) in which natural gas had been proven in commercial quantity. There was no set requirement for lease configuration.

Holders of petroleum and natural gas reservations who earned natural gas licences or leases were required to surrender those particular natural gas zones out of the reservation. Holders of natural gas licences were able at any time to surrender portions of the licence and return those rights to the reservation. The reservation holder was permitted to select petroleum and natural gas leases from any of the lands contained in the reservation as long as they met the required lease selection configuration (Section 2.2). The selected petroleum and natural gas leases excluded any of the rights previously selected as natural gas licences or leases.

2.6 Crown Reserve Natural Gas Licences

By 1952, it became apparent that certain areas of the province had

[4] The licence's zone was designated by use of a petrophysical log of the discovery well.

a greater potential for natural gas than crude oil. It also became obvious there was a need to stimulate long-range exploration for natural gas which still was considered marginally economic to produce. As a result, in natural gas prone areas the rights within Crown reserves (lands surrendered from reservations in each township) were made available for competitive bid. These rights were made available to the petroleum industry in the form of Crown reserve natural gas licences.

The tenure conditions for the Crown reserve natural gas licence were identical to those of the normal natural gas licence selected out of reservations. The maximum size of these licences was 36 sections and the term was two and a half years. Generally, the licensee was required to commence drilling a well within six months of the licence date. Holders of this type of licence were entitled to acquire 21-year natural gas leases based on the number and depth of productive gas wells drilled to the licensed zone(s).

2.7 Crown Reserve Drilling Reservations

Crown reserve drilling reservations were introduced in 1954 to stimulate drilling of specific target zones in a particular area believed to be highly prospective for crude oil production. The Crown reserve rights were made available at the petroleum industry's request. The requesting party had to specify the zone to which he was prepared to drill to earn petroleum and natural gas leases. The rights were then advertised by means of a sale notice that specified the number of sections which could be earned as lease upon drilling to the specified zone. The highest bidder was awarded the rights. The attention of all prospective bidders was therefore focused on a specific geological play in an area.

The size of the Crown reserve drilling reservation increased with

the depth of the prospective zone. If natural gas was encountered, the natural gas licence option was available which allowed 100 per cent lease coverage of the gas-bearing zone(s), up to a maximum of 36 sections. The natural gas licence option was only available if the reservation's specific target zone was penetrated.

The holder of a reservation was obligated to commence an on-going drilling program within one year of the reservation date. This program had to be carried out, with intervals of not more than three months between the abandonment of one well and commencement of the next well, until production in commercial quantity had been discovered. If the drilling obligation had been met, 25 per cent of the drilling reservation area could be converted to petroleum and natural gas lease. This form of drilling reservation could be renewed every six months, for a maximum of three years, from the date of its issuance. The entire cost of work performed on the drilling reservation could be applied as dollar credit toward the first year's rentals on the leases earned.

2.8 Petroleum and Natural Gas Permits

In 1962, in pursuit of deeper multi-zoned prospects, the focus of exploration activity shifted to the central basin area of the province. This resulted in a decline of activity in the southern and eastern portions of the province. To maintain a reasonable level of interest in the southern part of the province, the area was given a special designation: Block A lands. Also, a new form of disposition called a petroleum and natural gas permit was created. Block A lands encompassed the area between the fourth and fifth meridians from townships 1 to 64 inclusive. Crown reserves were abolished within this area.

The main feature of the petroleum and natural gas permit was that upon the completion of a well the permittee could convert the entire area to lease (100 per cent leasability). One-half the drilling

expenditures incurred prior to the conversion were applicable against the first year's lease rentals. The tenure condition for petroleum and natural gas permits was similar to that of Crown reserve natural gas licences (Section 2.6).

2.9 Significant Historical Events between 1970 and 1976

Petroleum and natural gas reservations, natural gas licences, natural gas leases, Crown reserve natural gas licences, Crown reserve drilling reservations and petroleum and natural gas permits within Block A lands were in effect at the end of 1969. During the 1970s a number of significant international, national and provincial events took place which had dramatic repercussions on the province's mineral rights tenure system. These events included:

1970 Middle Eastern countries, which produced most of the world's crude oil, wanted greater participation in major oil company operations in their countries.

1971 Canadian exploration activity by the major companies shifted from Alberta to northern frontier regions. The Government of Alberta recognized the need to stimulate the petroleum industry's activity in the province.

1972 Public hearings were held for the petroleum industry regarding methods of stimulating activity levels. The government recognized the need for greater accessibility to oil and gas mineral rights by the active smaller companies and thus began a review of the total mineral rights tenure system. The Alberta government introduced the Exploratory Drilling Incen-

tive System to encourage the search for new oil and gas reserves.

1973 Major price increases in crude oil were made by Middle Eastern producers after they formed the Organization of Petroleum Exporting Countries. The Alberta government increased royalties on crude oil. The petroleum industry's preoccupation with pricing and royalty matters resulted in its discontinuing oil and gas mineral rights tenure system discussions with the Alberta government.

1974 The Alberta Petroleum Marketing Commission was established to supersede price control by a small number of major multinational oil companies. Further Crown royalty increases occurred and changes to federal income tax legislation terminated the deduction of provincial royalties in calculating federal tax.

1975 Independent oil and gas companies expressed concern, also shared by the Alberta Department of Energy and Natural Resources, that the major companies were holding large lease blocks by virtue of production from shallow stratigraphic intervals and were delaying the development of the deeper geological zones. The Geophysical Incentive System was introduced to stimulate geophysical activity.

3. PRESENT OIL AND GAS RIGHTS TENURE SYSTEM

In 1976, major amendments were made to the oil and gas tenure system because of the following concerns:

1. The need to stimulate drilling activity.
2. The need to encourage the drilling and development of the deeper horizons below those already on production.
3. The decreasing possibility of discovering new oil pools extending over large areas.
4. The need of specific incentives to encourage natural gas exploration.
5. The need to make the Crown oil and gas mineral tenure system less complicated and easier to administer.

These concerns resulted in major amendments to the Mines and Minerals Act and changes to lease administration in the Petroleum and Natural Gas Lease Regulations. Major changes included:

1. Petroleum and natural gas permits, petroleum and natural gas reservations, Crown reserve natural gas licences, Crown reserve drilling reservations and petroleum and natural gas permits were no longer granted.
2. Two new forms of agreements were introduced: the petroleum and natural gas licence and the shorter-term five-year petroleum and natural gas lease.
3. Agreements in force before 1976, including the natural gas and petroleum and natural gas leases resulting there-

from, were allowed to continue until their term expired or the agreement holder requested cancellation.

4. Deeper rights reversion was established upon expiry of the initial lease term.
5. Filing was discontinued on undisposed petroleum and natural gas rights.
6. Petroleum and natural gas rights would only be posted upon industry's request.

3.1 Acquisition of Oil and Gas Rights

The Alberta Crown always retains title to its oil and gas minerals. Rights to these minerals are granted by means of agreement dispositions on a competitive basis to oil industry parties wishing to undertake the exploration and development of undisposed rights. Undisposed rights are made available upon the oil industry's request. Currently, the two forms of dispositions granted by the Alberta Crown are petroleum and natural gas leases, and petroleum and natural gas licences.

The "sale of petroleum and natural gas rights" means that the Crown, when offering petroleum and natural gas dispositions, is inviting interested parties to tender sealed bids for rights offered. Cash bonuses are used as a means of determining which party will be granted the right to drill for and produce oil and gas granted by the disposition being offered.

Petroleum and natural gas licences, as an exploratory type of agreement, are offered for sale in areas where:

a) Shallow oil and gas pools are non-existent;
b) Unexplored stratigraphic intervals underlie existing oil and gas pools;

c) A party commits itself to drilling a well on each of its requested scattered blocks (drilling islands).

Petroleum and natural gas leases are offered for sale in those areas where:

a) Previous drilling has identified the presence of hydrocarbons;
b) The development of existing pools is underway;
c) The drilling of a well on an existing agreement in close proximity is timed to a sale;
d) Insufficient lands exist to post a petroleum and natural gas licence large enough to warrant an exploration program.

3.1.1 Public Sales

[2] A person or firm wishing to acquire a petroleum and natural gas disposition from the Alberta Crown in an area may request that the department advertise the specific rights at a sale (posting request). When the Alberta Department of Energy and Natural Resources receives a posting request, it is reviewed in light of departmental guidelines. The rights may be advertised as requested, rights and lands added or deleted or the request refused.

The posted rights are then presented to the Crown Mineral Disposition Review Committee (CMDRC) for its review regarding any surface environmental concerns. The posted disposition may be subject to an addendum[5] if there are major surface concerns. These concerns may include critical fish and wildlife areas, recreational areas and natural areas. As a result of these concerns no access may be given to certain lands or access may be limited to certain times of the year;

[5] An appendix to a sale notice providing information on identified lands with surface access restrictions.

an example is certain of the zones within the Policy for Resource Management of the Eastern Slopes (Foothills area). Once the mineral rights are cleared by the CMDRC and approved by the department, a "Public Offering of Petroleum and Natural Gas Rights" notice (sale notice) is issued eight weeks in advance of the sale date.

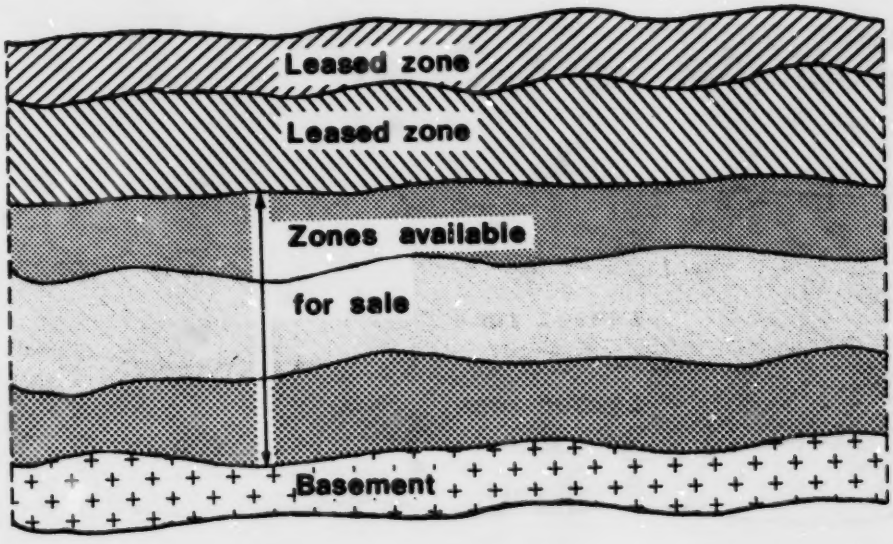
The sale notice specifies the terms and conditions of the sale together with the time, date and place that sealed offers for the advertised disposition will be accepted. Persons interested in acquiring the offered dispositions must submit their tender in a sealed container before the closing time indicated on the sale notice. The offer tendered must be in the form of cash, bank draft or certified cheque to satisfy the bonus, fee and rental for the disposition.

Holders of credits established under the Exploratory Drilling Incentive Regulations or Geophysical Incentive Regulations (Section 5) may request that their share of the bonus, fee and rental be satisfied from their incentive credit account. The request to apply incentive credits does not replace the need for submitting the full amount of monies with the offer.

The day following the sale, the name of the successful disposition purchaser, the bonus paid by him for each hectare and the average price per hectare are released. The department generally holds 25 public sales a year. The sale schedule is published a year in advance.

As a result of Alberta's past mineral tenure systems, the stratigraphic intervals or zones available for disposition fall into four general categories: all zones, deeper zones, single zone and shallow zones. These are depicted in Figures 2 and 3. It is important to note that any single disposition issued may consist of more than one zone category. A cross-section schematic representing all four categories of zones is illustrated in Figure 4. The schematic may appear somewhat complicated but to minimize future fragmentation the department attempts to post all zones available under any posted land parcel.

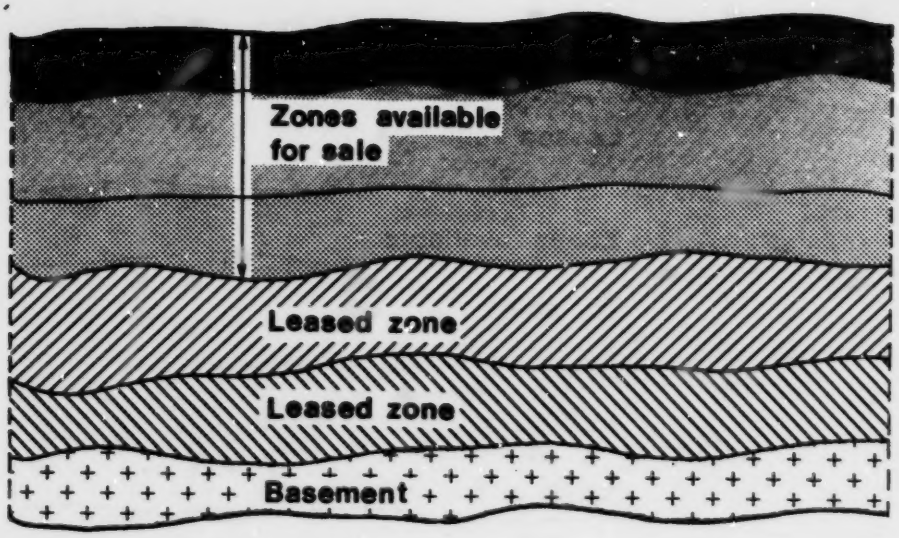
ALL ZONES



DEEPER ZONES

Figure 2. Two categories of zones available for disposition

SINGLE ZONES



SHALLOW ZONES

Figure 3. Other categories of zones available for disposition

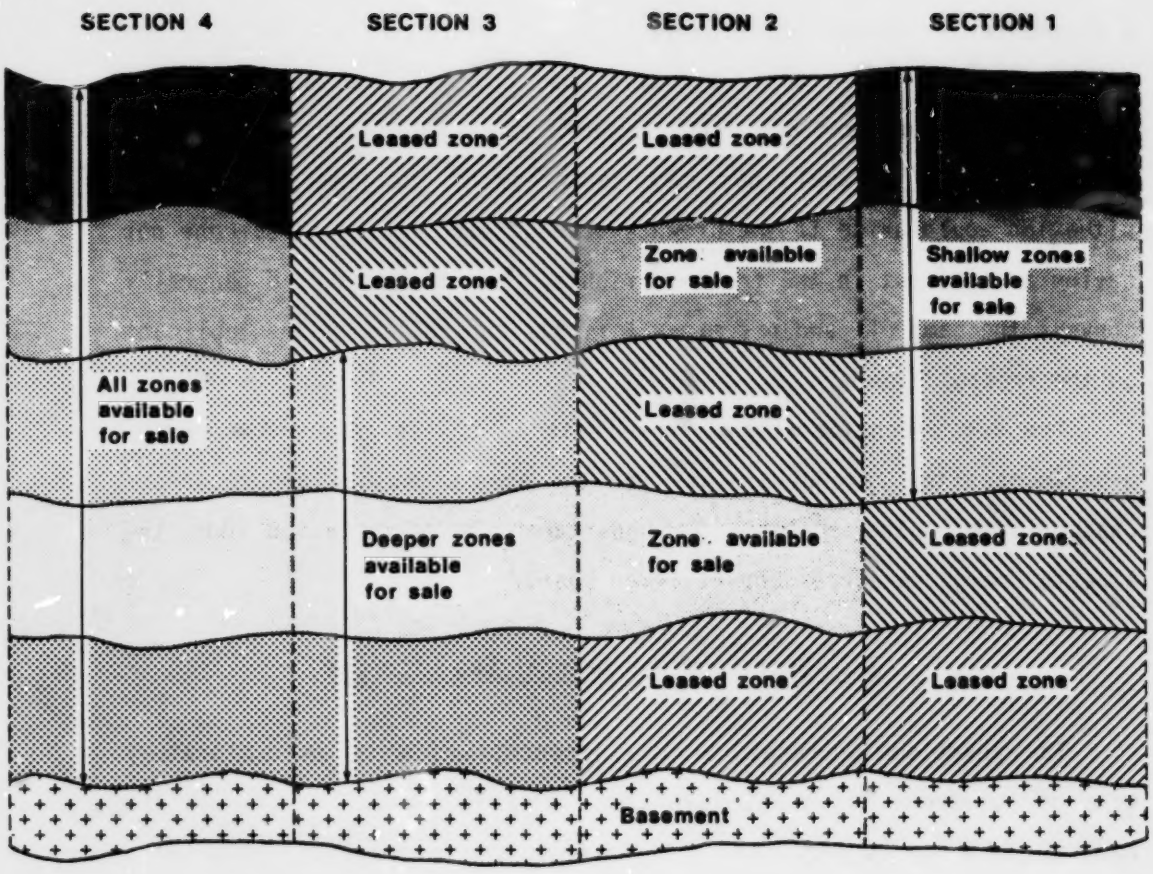


Figure 4. Combination of zones available

3.1.2 Private Sales

[3] In certain parts of the province, the Crown owns only a portion of the oil and gas rights in a quarter section and the balance is owned by a freeholder (a holder of oil and gas rights which are not owned by the Alberta Crown). When this situation has occurred, the department has only accepted applications from the holder of the freehold rights so that third parties would not take advantage of the freeholder. This situation could arise if the Crown's acreage were leased to someone not having an interest in the freehold rights. The lease granted generally conveys the same oil and gas mineral rights controlled by the applicant on the freehold lands.

The bonus consideration, on private sales, is determined by the department after careful analysis of the area's geology and reservoir capabilities. The analysis is undertaken in consultation with the Alberta Energy Resources Conservation Board.

3.2 Petroleum and Natural Gas Licences

[4] The petroleum and natural gas licence, which is an exploratory type of agreement, is granted in those areas where exploration in the form of drilling is required. The licence grants the right to drill a well or wells for petroleum and natural gas and to produce the same.

The licence term takes into account:

a) the province's varied climatic conditions, terrain and topography

b) the limited access to the forest and muskeg areas covering the northern portion of the province.

To make allowance for these unique features, the province has been divided into three natural geographic regions: the Plains, Northern

and Foothills areas (Figure 5). In order to allow approximately the same operational time frame, the term of a licence within each of these areas is two, four and five years, respectively.

The size of a licence is intended to support an exploration program which in its own right encompasses the major portion of a geological prospect. The maximum size of a licence is determined by the number of sections that could be earned in lease in accordance with Table 1 by the drilling of one well to the estimated base of the sedimentary column in the area. The maximum licence size established for each area is 29 sections in the Plains, 32 sections in the Northern and 36 sections in the Foothills. The minimum size of a licence is one section.

In order for a licensee to earn five-year petroleum and natural gas leases, he must drill at least one well. Each lease-earning well entitles the licensee to a specific number of sections which are calculated in proportion to the total number of metres drilled. The lease entitlement areas are compiled in Schedule B of the Petroleum and Natural Gas Licence Regulations (Table 1).

[5] The petroleum and natural gas rights selected as lease must contain whole sections or the whole of any fractional section contained in the licence. Where a lease-earning well is capable of oil production, then the location[6] of the lease may include or consist of oil well drilling spacing units.[7]

To understand lease earnability better, consider the following case. A licensee drills a 1500 metre well in the Northern area. Regardless of his drilling results he is entitled to nine lease sections (Table 1). If the licensee happens to make a gas discovery,

[6] The area described in the agreement.

[7] The maximum area of land stipulated by the Energy Resources Conservation Board -- having regard to well drainage, density and other factors -- within which oil and/or gas wells can be drilled or produced. The normal spacing unit for oil is a quarter section; for natural gas, one section.

Figure 5. Petroleum and natural gas licences area map

TABLE 1

SCHEDULE B OF THE PETROLEUM AND NATURAL GAS LICENCE REGULATIONS

1 Where a lease-earning well is drilled at least to a depth shown in Column 1 in the following Table (the depth being hereinafter called the "Column 1 depth") but not below the next succeeding depth shown in Column 1, the number of sections for which the licensee may apply as locations under petroleum and natural gas leases is

(a) the number of sections shown in the Column for the appropriate area opposite the Column 1 depth, plus

(b) the number of sections or parts of sections calculated by multiplying the difference between the Column 1 depth and the total drilled depth of the well by the Incremental Factor in Column 5 opposite the Column 1 depth.

Column 1 **DEPTH** (in metres)	Column 2 **PLAINS AREA** (sections)	Column 3 **NORTHERN AREA** (sections)	Column 4 **FOOTHILLS AREA** (sections)	Column 5 **INCREMENTAL FACTOR** (sections per metre)
150	3	5	8	nil
300	3	5	8	0.0033*
600	3	6	9	0.0033
900	4	7	10	0.0033
1200	5	8	11	0.0033
1500	6	9	12	0.0033
1800	7	10	13	0.0033
2100	8	11	14	0.0050**
2400	9 1/2	12 1/2	16	0.0050**
2700	11	14	18	0.0066
3000	13	16	20	0.0066
3300	15	18	22	0.0066
3600	17	20	24	0.0066
3900	19	22	26	0.0066
4200	21	24	28	0.0100
4500	24	27	31	0.0100
4800	27	30	34	0.0100
5000	29—	32—	36—	nil

*As to the Plains area, read "nil" instead of 0.0033
**As to the Foothills area, read "0.0066" instead of 0.0050
—Maximum

he may want to select the lands around his discovery, as shown in Figure 6.

As an incentive to encourage the drilling of a lease-earning well as soon as possible, the $2.50 a hectare annual rental for the remainder of the licence term is waived when a well is drilled. The rental is waived on that portion of the licence earned in lease if selection had been made at that time.

To follow through on the example, if the 1500 metre well was drilled in the first year of the licence term, rentals would be waived on the nine sections earned. This would amount to $5,760 a year for the remaining three years of the licence term ($17,280 total).

The Petroleum and Natural Gas Licence Regulations allow the grouping of two licences, provided they are within 3.2 kilometres of each other. The department must approve the grouping request before the drilling of the initial lease-earning well.

When a licence is grouped and a well is drilled on either licence, the area which can be selected as lease includes any of the grouped area, regardless of the licence boundaries. The provision of licence grouping allows the licensee flexibility in the efficient and orderly development of a geological prospect and allows the licensee to drill and develop the core of his geological prospect. This provision also has particular advantage where a deep lease-earning well or wells earns more sections than is contained in any one licence. In this situation the licensee may select lease sections anywhere within the group's area up to a maximum of the total number of sections earned by a deep well or a number of wells drilled on a licence.

3.3 Petroleum and Natural Gas Leases

[6] Petroleum and natural gas leases grant the lessee the exclusive right to explore for, work, win and recover all petroleum and natural

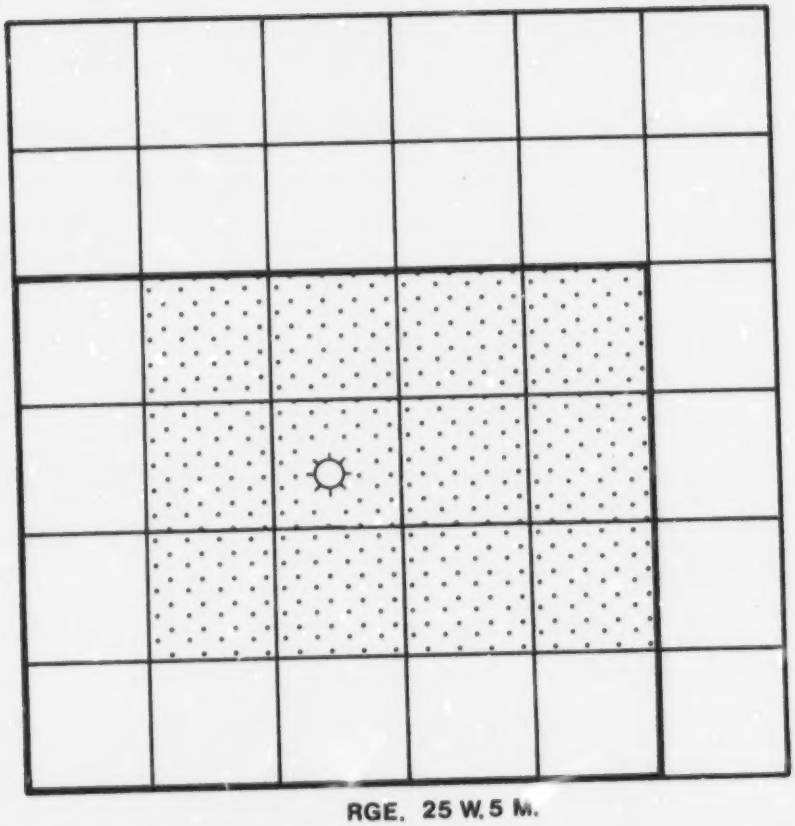


Figure 6. Potential lease selection in Northern area

gas within and under the lands described in the lease.

The initial term of petroleum and natural gas leases issued before June 1, 1962, was 21 years. These leases emanated from prospecting permits, petroleum and natural gas reservations and public sales. The last 21-year petroleum and natural gas lease was issued in November, 1972.

All petroleum and natural gas leases granted out of petroleum and natural gas permits, reservations and leases purchased at public sales between 1962 and July, 1976, had an initial term of 10 years. The last new 10-year lease granted emanated from the last petroleum and natural gas reservation issued in June, 1976, which expired in December, 1982. Also, the final 21-year natural gas lease was also issued from this last reservation.

In July, 1976, the initial petroleum and natural gas lease term became five years. All leases in force before this date were allowed to continue until their initial term expired.

In 1976, drilling obligations were imposed on existing 10-year leases, in order to bring them more in line with the new five-year lease term. This was similar in principle to those drilling obligations already in place on 21-year leases. A lessee is required to drill a well on his 10-year lease before its seventh anniversary and on 21-year leases before their eleventh anniversary. There is no provision for the grouping of five-year leases since they are continued solely on the basis of demonstrated productivity.

In lieu of drilling, lessees of 10-year and 21-year leases have the option of paying drilling penalties to have the drilling requirement extended for a year. The drilling penalties for both 10-year and 21-year leases are $2.50 a hectare for the first drilling penalty year, $7.50 for the second, $12.50 for the third and $22.50 for the fourth year. Drilling requirements are satisfied if the department considers the location capable of producing oil or gas in paying quantities.

This automatically includes spacing units adjacent to producing wells and unitized lands.

[7] The drilling requirement for a lease or a number of leases can be met by grouping the leases and drilling a well on the grouped leases. A lessee may submit his lease grouping application to the department prior to spudding his well or within 60 days of the finish drilling date. This will meet the drilling requirement for all the leases in the group. The number of lease sections which can be grouped in the case of 10-year leases is based proportionately on the depth of the well drilled on the lease group. Table 2 outlines the number of sections which can be grouped, depending on the geographic area and the depth of the well drilled. This table is attached as Schedule B to the Petroleum and Natural Gas Lease Regulations.

The number of 21-year lease sections that may be grouped are also dependent on the depth of the well drilled on the lease group as follows:

Well's Projected Depth (Metres)	Number of Sections Which Can Be Included in a Group
Less than 900	6
900 or more but less than 1800	8
1800 or more but less than 2400	12

Two additional sections can be grouped for every 300 metres drilled in excess of 2400 metres.

In order to group 10-year petroleum and natural gas leases, they must all be located in the same geographic area, that is, the Plains, Northern or Foothills area. Twenty-one year leases do not have this requirement; they may be grouped anywhere in the province.

TABLE 2

SCHEDULE B OF THE PETROLEUM AND NATURAL GAS LEASE REGULATIONS

Where the projected drilled depth of the well or the actual drilled depth of the well, whichever applies, is at least one of the depths shown in Column 1 of the following Table (the depth so shown being hereinafter referred to as the "Column 1 depth") but not greater than the next succeeding depth shown in Column 1, the maximum area that may be grouped shall consist of

(a) the number of sections shown in the Column for the appropriate area opposite the Column 1 depth, plus

(b) the number of sections or parts of sections calculated by multiplying the difference between the projected drilled depth or actual drilled depth, whichever applies, and the Column 1 depth, by the Incremental Factor in Column 5 opposite the Column 1 depth, taken to the nearest quarter of a section.

Column 1 DEPTH (In metres)	Column 2 PLAINS AREA (sections)	Column 3 NORTHERN AREA (sections)	Column 4 FOOTHILLS AREA (sections)	Column 5 INCREMENTAL FACTOR (sections per metre)
150	3	5	8	nil
300	3	5	8	0.0033*
600	3	6	9	0.0033
900	4	7	10	0.0033
1200	5	8	11	0.0033
1500	6	9	12	0.0033
1800	7	10	13	0.0033
2100	8	11	14	0.0050**
2400	9 1/2	12 1/2	16	0.0050**
2700	11	14	18	0.0066
3000	13	16	20	0.0066
3300	15	18	22	0.0066
3600	17	20	24	0.0066
3900	19	22	26	0.0066
4200	21	24	28	0.0100
4500	24	27	31	0.0100
4800	27	30	34	0.0100
5000	29—	32—	36—	nil

*As to the Plains area, read "nil" instead of 0.0033
**As to the Foothills area, read "0.0066" instead of 0.0050
—Maximum

3.3.1 Lease Continuation

When leases reached the end of their initial term before 1976 the lease term was continued if the lands in the lease were productive. Not all the lands were necessarily continued, just because a lease contained a productive well. The section which contained the productive well automatically continued but the remaining lands were examined as to their productivity on a section by section basis. If any of the lands were determined to be non-productive, they were removed from the continued lease. An exception to this rule was that with one productive gas well on a 21-year natural gas lease, the whole lease was continued regardless of size.

Once a lease term had been continued, it remained continued as long as it met one of the following criteria:

a) It was part of a well's spacing unit;
b) It was subject to a unit agreement;
c) It was part of a spacing unit where the drilling of an offset well had been extended;
d) The department considered the lands capable of production.

A lessee whose lands were continued retained ownership to all geological horizons, regardless of which zone(s) in the well was productive. Lease continuation at that time only addressed the area encompassing the productive horizon (pool).

It was recognized in the early 1970s that many leases were being continued solely on the basis of proven productivity from shallow stratigraphic intervals, and that the geological zones below these shallow intervals were not being explored. This resulted in a third-dimension being added to lease continuation by legislative changes in

1976. A lease would now be examined not only as to its areal extent of productivity but also vertically as to the deepest stratigraphic interval considered productive in paying quantity.

[8] The addition of this third dimension meant that all geological zones below the base of the deepest productive zone would revert to the Crown. The reversion of the non-productive zone would be handled in the same manner as non-productive lands. This is referred to as the deeper rights reversion.

Petroleum and natural gas leases issued after July 1, 1976, were continued in this three-dimensional manner; the first occurred in July, 1981. In order to give lessees of 10-year and 21-year leases time to explore the rights below existing productive horizons, deeper rights reversion on the leases was delayed until January 1, 1983, or until their initial term expiry date, whichever occurred later.

Lease continuation is now granted at the end of a lease's initial term for rights to the base of the deepest productive stratigraphic interval over the whole lease location. If the department, upon review of the lessee's data, concludes the deepest productive stratigraphic interval is probably not productive throughout the lease location, it will request the lessee to demonstrate its productivity. At present, lease continuation is initially considered on a lease by lease basis; eventually it will be reviewed on a spacing unit by spacing unit basis.

[9] The simplest form of lease continuation is where lands form part or all of the production spacing unit for a producing well. These lands will be automatically continued to the base of the deepest productive stratigraphic interval in that producing well, as illustrated in Figure 7.

[10] Similarly, where an entire lease is part of a unit agreement or the lease is subject to a drilling obligation under an offset requirement (Section 3.3.2), lease continuation would be automatically granted

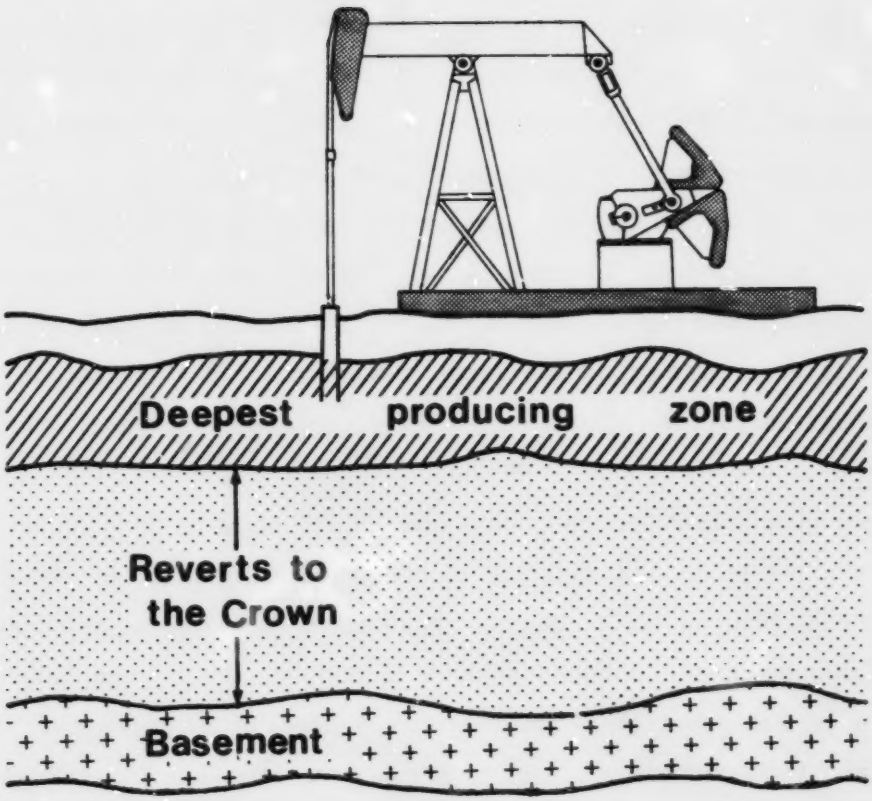


Figure 7. Expiring lease with productive well

to the base of the deepest productive stratigraphic interval in the unit or the offset spacing unit.

Lease continuation becomes more complex when the lease is not part of a producing well's spacing unit, a unit operation or a direct offset. In these more complex cases, the department requires the lessee or lease operator to submit technical data demonstrating the productivity of the lease in paying quantity. If the department is satisfied that a portion of the lease has been demonstrated to be capable of production in paying quantity, that portion is continued.

[11] Technical data submitted by a lessee may be inconclusive, that is, a portion of the lease is "probably productive" (unproven) in a specific stratigraphic interval. In this type of situation, the department may allow all or a portion of the lease to continue for a special one-year continuation period. Examples of this are shown in Figures 8 and 9.

The one-year period allows the lessee time to undertake further drilling to confirm the productivity of the probably productive interval(s). This type of continuation requires a performance security deposit of $25 a hectare, refundable in whole or in part, if the lessee drills a well and penetrates the unproven interval. The deposit is refunded for that portion of the location evaluated by the drilled well.

[12] Provided the required well is commenced during the one-year special continuation period and is drilling over the new expiry date, two further special continuations of one-year each are possible if the lease is located in the Northern or Foothills areas. A well must be drilling over the expiry of each extension period to test the probably productive zone. Additional security deposits are required for these further special continuation periods and the department may set additional terms and conditions. The security deposit for any lapsed year is not refunded.

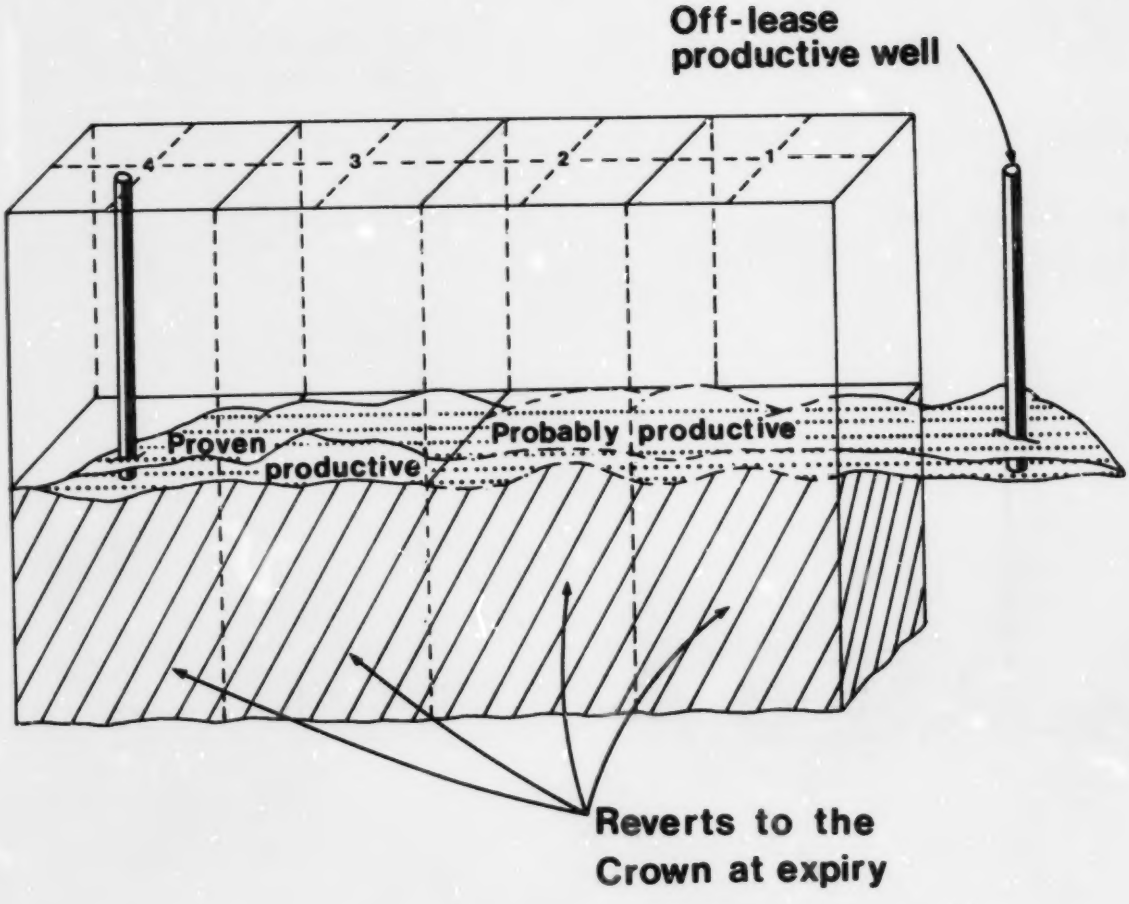


Figure 8. Case 1: Expiring lease with shallow probably-productive lands

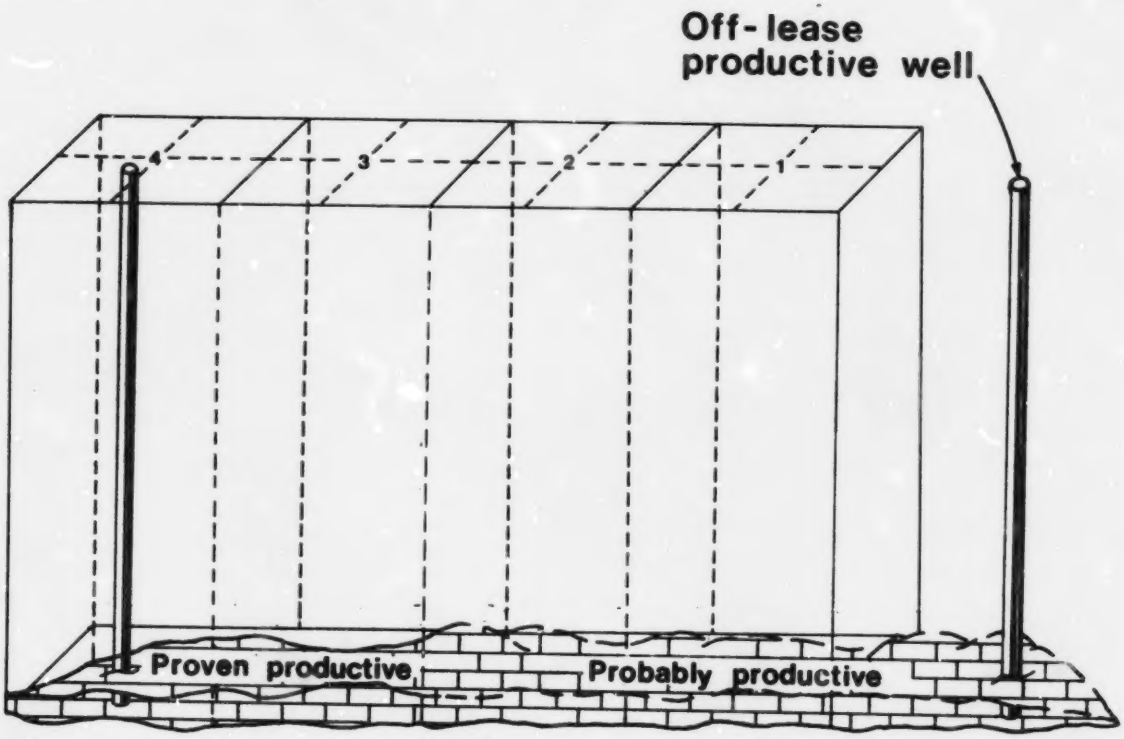


Figure 9. Case 2: Expiring lease with deep probably-productive lands

At the expiry of the special continuation periods, the lease is once again reviewed as to its productivity in paying quantity. Based on the information acquired during the special continuation periods, all the lease will be continued or a portion of the lands to the base of the productive stratigraphic interval. The lease or a portion may be cancelled if productivity is not proven conclusively. Figures 10, 11 and 12 illustrate combinations of lease continuations following drilling during the special continuation periods.

[13] If a well is drilling over the expiry date of a lease, the spacing unit (up to one section) automatically continues for 90 days after the well finishes drilling. This allows the lessee time to evaluate his drilling results. In the event a second well commences drilling within that 90-day period, the continued portion of the lease further continues for an additional 90 days after the second well finishes drilling. This procedure carries on for any number of wells drilled during the 90-day continuation periods; the spacing unit is always continued for 90 days after the last well is drilled. Upon the expiry of the final 90-day period, if the drilling and testing results prove the spacing unit productive, it continues under the normal continuation criteria.

[14] Once a lease or a portion of a lease is continued, the subject lands continue so long as they are productive in paying quantity. When any lands within the continued lease cease to be productive they are cancelled. The most obvious cessation of productivity is when a well on the lease or in the immediate vicinity of the lease is abandoned. Once the lease or portion of the lease is identified as possibly being unproductive, the department serves the lessee with a notice requesting him to demonstrate the lease to be productive within the ensuing six months. This notice covers a specific stratigraphic interval underlying the whole or a portion of the lease which the lessee must demonstrate as productive. If the lessee is unable to demonstrate the

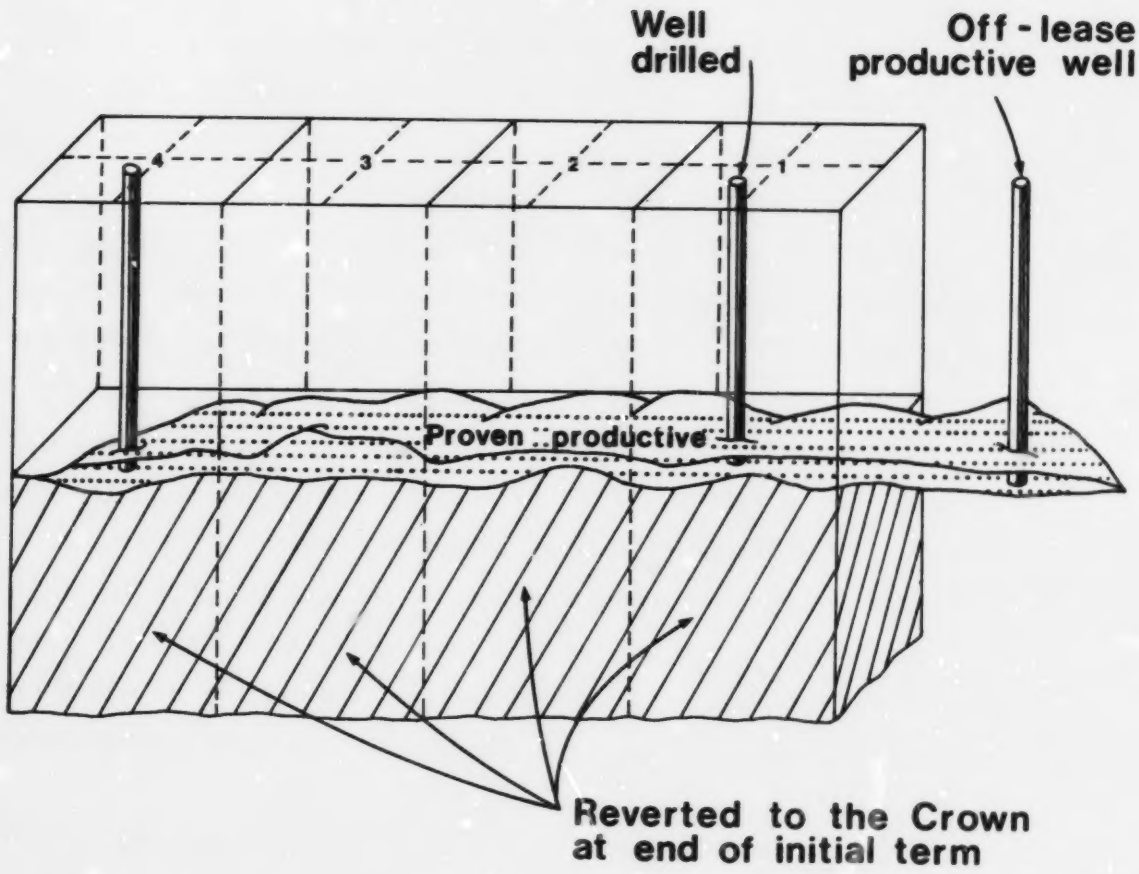


Figure 10. Case 1: Lease review following special continuation period

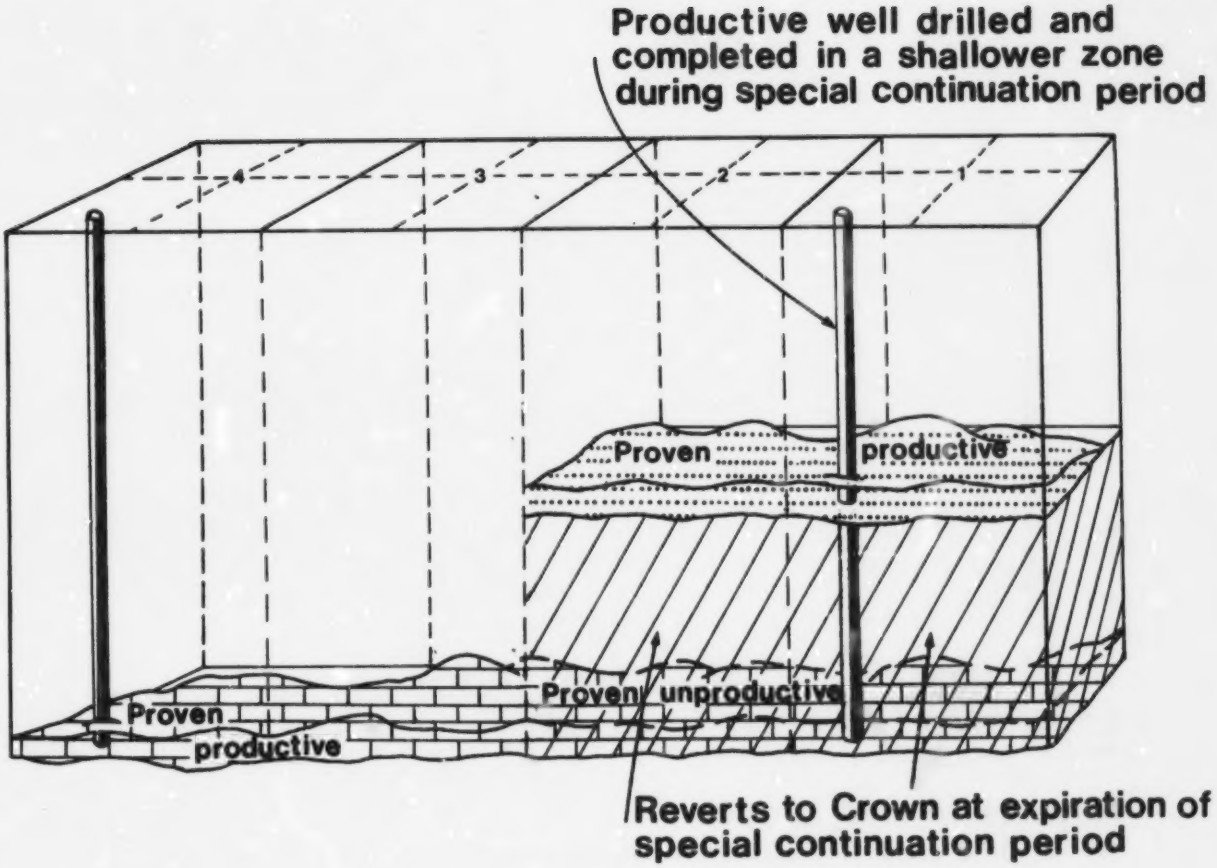


Figure 11. Case 2: Lease review following special continuation period (one well drilled)

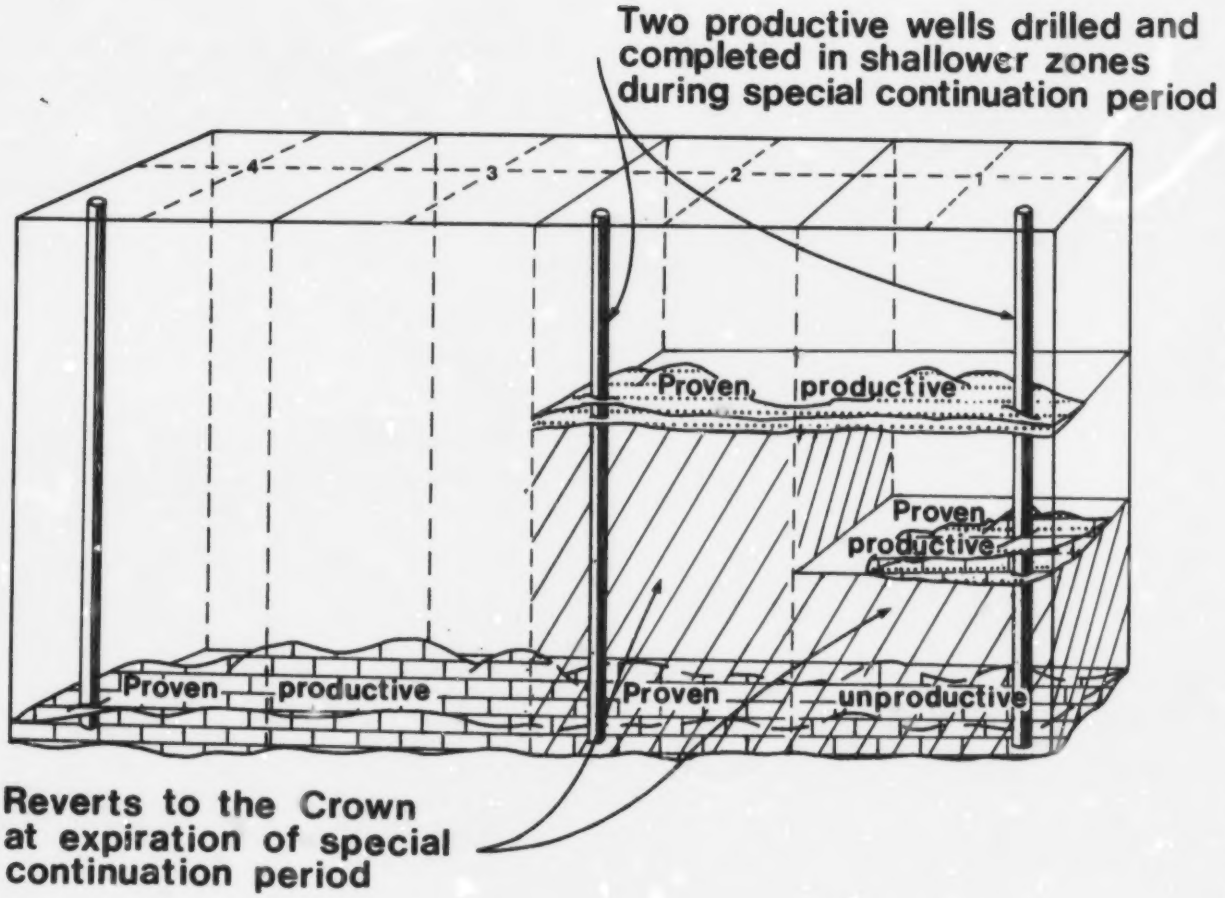


Figure 12. Case 3: Lease review following special continuation period (two wells drilled)

productivity of the stratigraphic interval contained in the notice, the non-productive portion of the lease is cancelled. Figure 13 illustrates a situation where the Crown would require the lessee to demonstrate that the lease is productive.

[15] A lease may contain more than one productive stratigraphic interval. The entire lease may be productive from the shallower interval but the deepest interval is not productive throughout the lease area. In this situation, the department forwards a notice to the lessee identifying the specific lands and stratigraphic interval not considered productive. The lessee has one year in which to demonstrate productivity. An example of this situation is illustrated in Figure 14.

Demonstrating the productivity of a stratigraphic interval subject to a notice generally necessitates the drilling of a well on the lands. If a well is not drilled, the lessee must provide the department with conclusive technical data from the well drilled on the lease or from offsetting wells to prove the lease productive from the stratigraphic interval addressed in the notice.

3.3.2 Offset Obligations

[16] When a well is drilled on rights not owned by the Crown (freehold rights) and the well is placed on production, the offsetting Crown lessees are subject to an offset drilling obligation, assuming the Crown spacing unit is undrilled. The reason for the automatic obligation is that the producing freehold well will begin to drain the Crown's oil and gas reserves from the producing stratigraphic interval.

The department serves the offsetting Crown lessee with a notice to commence the drilling of a well within 90 days of the freehold well having being placed on production on the offsetting Crown spacing unit. The lessee may elect to extend the commencement date by paying compens-

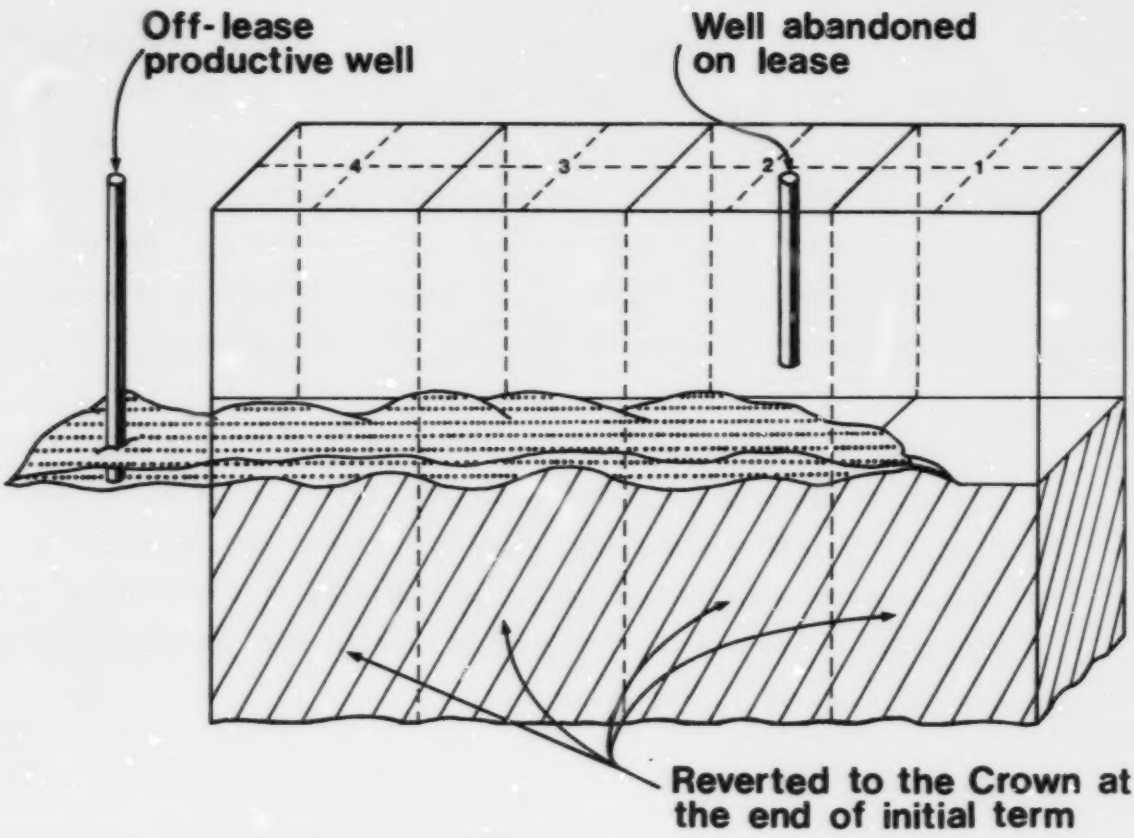


Figure 13. Lease subject to six-month productivity notice

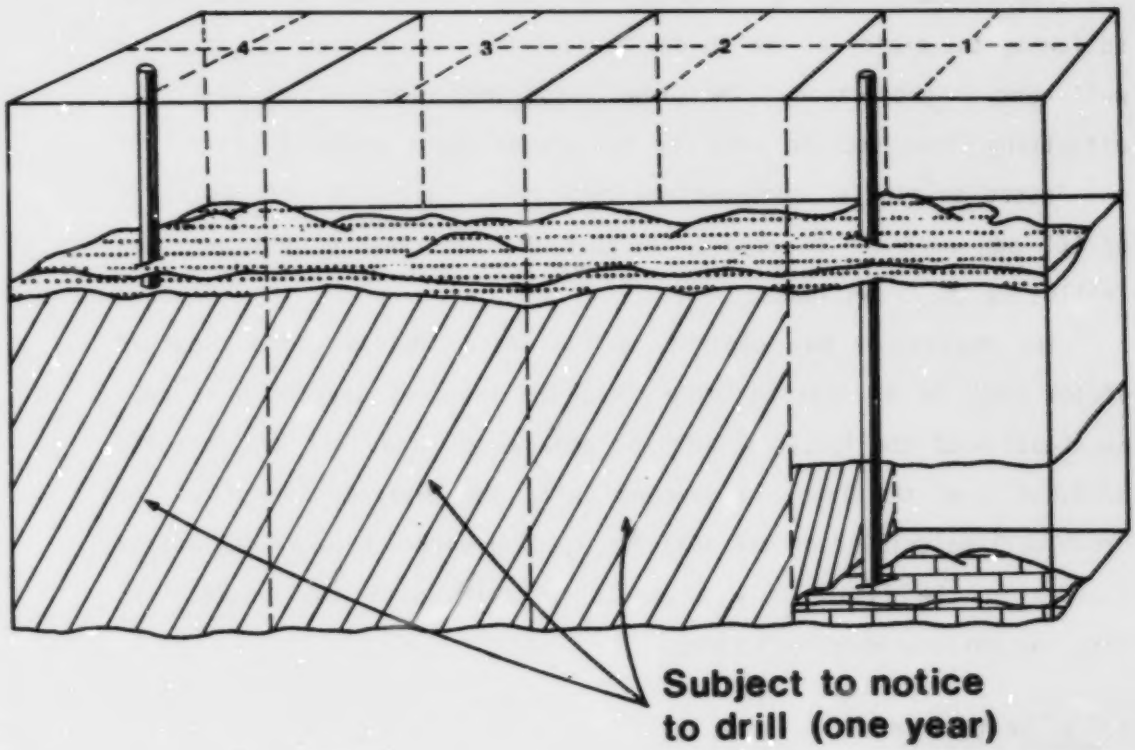


Figure 14. Lease subject to one-year productivity notice

atory royalty. The compensatory royalty rate is calculated on the basis of the volume produced from the offsetting freehold well. This compensatory royalty for the first year is one-half the normal royalty which would have been payable to the Crown had the freehold well been drilled on the Crown lease.

Compensatory royalty becomes due the first day of the month following the expiry of the 90-day period which began when the freehold well went on production. The Crown lessee may elect not to drill the offsetting Crown spacing unit for the second and subsequent years. If the lessee so elects, compensatory royalty is calculated on the basis of 100 per cent of the royalty payable if the freehold well had been drilled on the Crown lease.

The department may consent to the lessee drilling the required offset well in a location other than the adjacent spacing unit upon examination of the lessee's detailed geological data. If gas is being produced from the freehold spacing unit, the department insists the Crown well be drilled on the adjacent spacing unit. Natural gas offset notices may be issued only after consultation with the lessee. To date, no notices have been issued.

3.3.3 Unitization

[17] Parties having an interest in a petroleum and/or natural gas pool or reservoir may join together to produce the reservoir contents without regard to the leasehold boundaries. This is called unitization, and the jointly operated area is called the unit area. The unit area is operated as though all lessors were a single lessor and all lessees were a single lessee. Unitization has become an important tool in maximizing reservoir recovery, preventing waste and reducing operating costs.

Once all the working-interest owners have agreed to form a unit,

one of the larger interest holders is designated as the unit operator. The unit operator is responsible for carrying out all necessary field operations, including drilling, producing and maintenance.

Each working-interest owner contributes toward the unit costs in proportion to his ownership and receives his entitled share of production, whether or not there is a well physically located on his lease. In line with good conservation practice, there is no need to drill a well in every spacing unit or on each lease within the unit boundary. Only those wells considered essential for the efficient production of the unitized pool are drilled and operated.

The most fundamental task which must be solved in negotiating a unit is the allocation of each participant's unit equity. The method used to determine each owner's share of the unitized pool is to assign a value to each lease or portion of a lease within the unit boundary; this is called a tract participation factor. The factor is then expressed as a percentage of the pool's potential. To determine a tract's participation factor, certain technical parameters must be established. These include:

a) Areal extent of the pool
b) Pool's productive capacity
c) Initial oil and/or gas in place
d) Pool's estimated recoverable reserves
e) Pool's productive pore volume
f) Cumulative production
g) Present worth of each tract
h) Production decline curves
i) Permeability

Unitization is particularly suitable in areas where enhanced recovery or pressure maintenance schemes have become necessary for a

reservoir's efficient production. Allowing expenses and revenues to be shared equitably, unitization is the most equitable method of operation, provided that the entire pool is included in the unit and all the owners are able to reach agreement.

The department becomes involved only in units where the Crown's oil and gas rights are within the unit area. The department reviews each proposed unit agreement, verifying that the area being unitized covers the entire pool or at least the major portion of the pool and that no unproductive tracts have been included. The fairness of the tract participation factor allocated to the Crown's mineral rights is also reviewed. Careful consideration is also given to the terms and conditions of the unit agreement, because the Crown leases or parts thereof covered by the unit are amended to the extent necessary to conform to the unit agreement. The department does not act as a regulatory body but solely as a major lessor.

Unitization is not compulsory in Alberta. The Mines and Minerals Act contains special provision governing Crown leases within units. Regulations governing unit operations are the jurisdiction of the Energy Resources Conservation Board pursuant to the Oil and Gas Conservation Act. It has not been necessary to proclaim the unitization sections of the Oil and Gas Conservation Act as compulsory because generally unitization is in the best interest of most companies.

4. GEOPHYSICAL EXPLORATION

[18] All geophysical exploration work within the province is governed by the 1978 Exploration Regulation. Before 1978, geophysical activity approvals were required only in the Green Area (see Figure 15) of the province and were granted by the Alberta Forest Service under authority of the Geophysical Regulation.

To ensure that lands within specific areas are disposed in accordance with their best use, to restrict settlement to those areas where social services are reasonably available and to reduce the risk of forest fires, the provincial government has divided the province into three areas (Figure 15):

1. White or settled area
2. Yellow or fringe area which is open for settlement
3. Green or forest zone which is closed to settlement.

The Exploration Branch within the Mineral Resources Division, as co-ordinator for all government departments having direct involvement in exploration approvals, acts as the "one window" for the oil and gas industry's access to government. The branch refers industry's exploration applications within the Green Area to the Alberta Forest Service. Most of the lands within the Green Area are public (Crown) lands; these and the acquisition of all surface rights are administered by the Public Lands Division of the department. Most of the lands in the White and Yellow areas are privately owned. Only where public lands are involved in the White and Yellow areas are exploration applications referred to the Public Lands Division. Copies of exploration applicat-

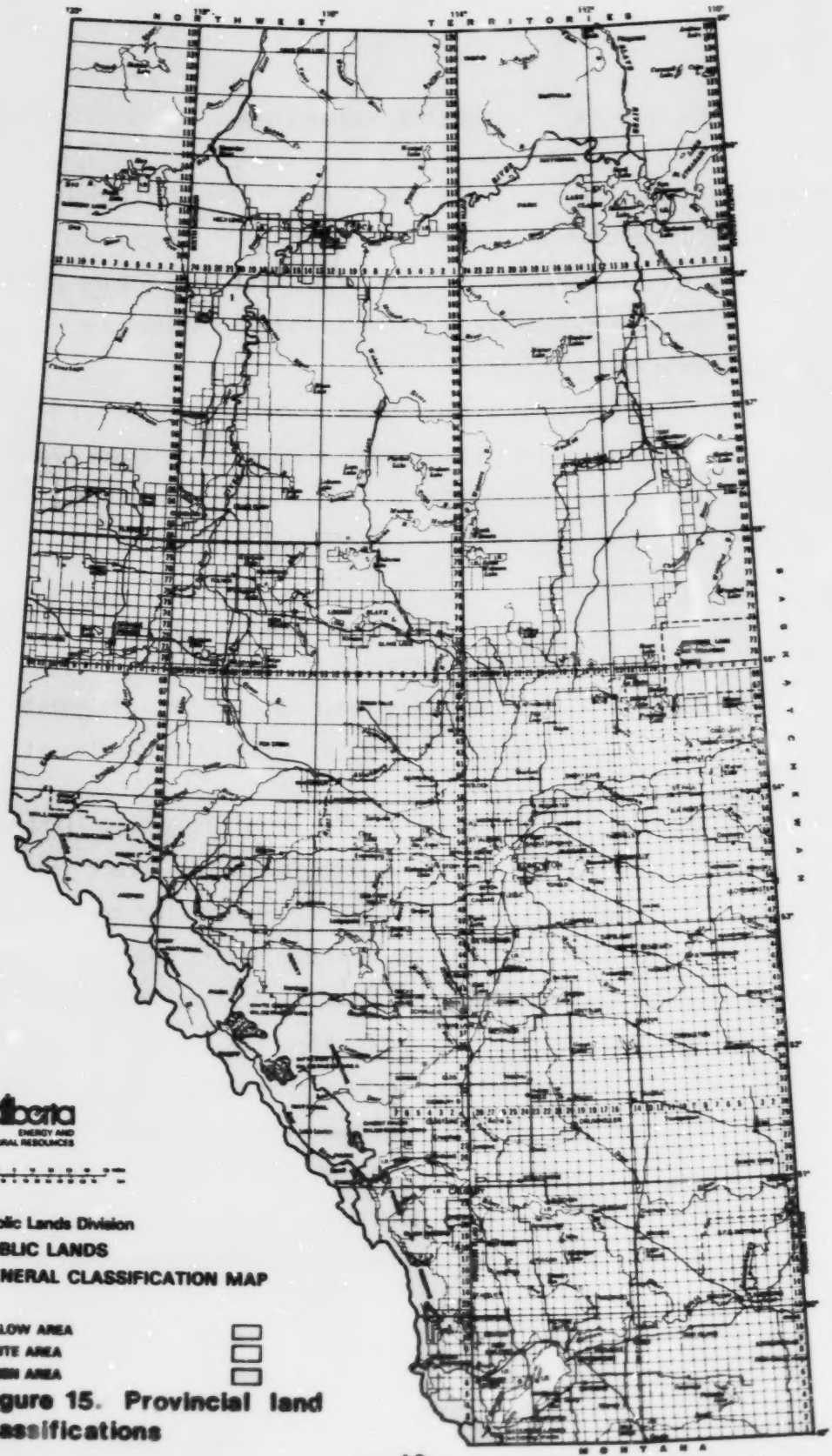


Figure 15. Provincial land classifications

ions are also referred to other government departments if statutes, regulations, services or programs administered by them are directly affected.

[19] Before an exploration program is conducted on public lands anywhere in the province, a preliminary plan is to be submitted to the Exploration Branch. This plan must include information as to:

1. The minerals being explored;
2. The type of equipment to be used;
3. The expected commencement and completion dates of the program;
4. The names and addresses of the geophysical licensee and permittee (the permittee is normally the contractor who performs the field work);
5. A map showing the area to be explored, with the complete land description and the location of all existing and new proposed seismic lines.

Each exploration application is reviewed by the appropriate department involved. Concerns addressed by other departments are reviewed by the Exploration Branch and incorporated as operating conditions to the exploration approval granted to the applicant. The Exploration Regulation provides for the issuance of an exploration approval or rejection within 10 days following receipt of an application. In some instances an applicant's program or portions of a program are rejected because of identified environmental or ecological concerns which cannot be mitigated. An applicant must obtain prior approval for any deviations from the approved program. Within 60 days of the program's completion a final plan must be submitted to the branch, showing the actual program conducted in the field.

The Exploration Regulation governs the forms of authorized explor-

ation as well as the department's criteria for the use of public lands (including forest areas), public highways and roads, and restricted areas during an exploration program.

Geophysical operators under the Exploration Regulation are authorized to gain surface access in order to conduct exploration work on unoccupied public lands and roadways which are under the administration of the Alberta Department of Energy and Natural Resources and the Alberta Department of Municipal Affairs. When an individual or corporation holds a lease with the Crown on a road allowance, the operator
[20] performing the exploration work (permittee) must first negotiate in good faith with the surface lessee to gain access. If negotiations are non-productive, the operator may give 48 hours of written notice to the surface lessee and undertake the program. The notice must contain:

1. A description of the location and type of program being conducted;
2. An undertaking by the operator that he will be liable for any damages to the lessee's property resulting from the program operation.

The Exploration Regulation does not grant surface access for geophysical operations on privately owned land. An operator contemplating a program on private land must negotiate access with the landowner. If access negotiations are unsuccessful, there is no legislative recourse for an operator to gain entry on privately owned land.

Every operator desiring to conduct exploration work in the province must obtain an exploration licence from the Exploration Branch.
[21] Owners of exploration equipment must acquire an exploration permit prior to the equipment's use in the province. The permit holder must notify the Exploration Branch of the location of each field crew, the name of the crew's supervisor, the amount of exploration work conducted and the completion date of each program.

5. INCENTIVE PROGRAMS

In July, 1972, the Alberta government approved the Natural Resources Revenue Plan relating to crude oil and natural gas. The basic objective of the plan was to increase the province's revenues. Oil and gas royalty revenues accruing to the Government of Alberta are intended to provide a reasonable return to the people of Alberta while providing a fair and equitable return on invested risk capital spent by Crown mineral leaseholders. The revenue plan paved the way for policies which created specific incentives that increased the participation of small oil and gas investors.

An integral part of the Natural Resource Revenue Plan was the implementation of the Exploratory Drilling Incentive System (EDIS) for exploratory wells. The main objective of this program was to encourage wildcat drilling and thus the discovery of new oil and gas pools. EDIS was designed to return oil and gas revenue to active explorers. In January, 1975, the Geophysical Incentive System (GIS) was introduced. This program had the same objective as the EDIS program but was specifically designed to stimulate seismic exploration in the province.

5.1 EXPLORATORY DRILLING INCENTIVE SYSTEM

The Exploratory Drilling Incentive System (EDIS), introduced by
[22] the 1972 Exploratory Drilling Incentive Regulations, was established for a two-year period. However, subsequent regulations extended the program, with minor modifications, to March 31, 1984. Under EDIS there are two forms of incentives for qualifying exploratory wells: first, drilling credits and, secondly, crude oil or gas royalty exemptions.

The Energy Resources Conservation Board (ERCB) determines those wells which qualify as exploratory.

Drilling incentive credits under this system are calculated on the basis of the number of metres drilled in accordance with Schedules N and O of the Exploratory Incentive Regulations (Tables 3 and 4). The rates outlined in the schedules take into account well costs within each of the distinct geographic areas of the province (Plains, Central, Northern or Foothills) as shown in Figure 16. The relative costs of drilling in the Plains area are substantially less than in the Northern area where access is limited in the forested and muskeg-covered terrain. Also, the complex geology and topography of the Foothills area makes it a very costly area in which to drill.

The ERCB determines, concurrent with the granting of a well licence, whether a well qualifies as an incentive exploratory well. If a well qualifies, it is certified as an incentive exploratory well. Upon completion of the incentive well, the ERCB also determines the intervals of depth that qualify for incentive credits, based on data supplied by the well's licensee. The ERCB notifies the Department of Energy and Natural Resources as to the interval depth and class type qualifying for incentive credit in the incentive exploratory well. There are two types of class interval, Class A and Class B, each determining credit amount earned.

The broad criterion used by the ERCB to determine whether or not a well is a exploratory incentive well is its proximity to previously drilled wells. Generally, an incentive exploratory well is one which is drilled 4.8 kilometres from a pre-existing well or 150 metres below the zone drilled by a pre-existing well within the 4.8 kilometres
[23] (Figure 17). Schedules N and O of the Exploratory Drilling Incentive Regulations (Tables 3 and 4) spell out the credit amount earned by Class A and Class B intervals. Figure 17 illustrates case examples of the ERCB's application of the criterion.

TABLE 3

SCHEDULE N OF THE EXPLORATORY DRILLING INCENTIVE REGULATION, 1983, CLASS A INTERVAL

The Class A interval of an incentive exploratory well, the drilling of or deepening of which commences on or after May 1, 1983, and before November 1, 1983, shall be determined by the Board as the interval that

(I) has not been duplicated by a pre-existing well within 2.4 kilometres of the incentive exploratory well, **[CASE 1 and 2 in Figure 17]**

(II) occurs more than 150 metres below the base of the deepest significant occurrence of crude oil or gas that, in the opinion of the Board, has been penetrated by a pre-existing well within 4.8 kilometres of the incentive exploratory well, and **[CASE 4 and 5 in Figure 17]**

(III) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that, in the opinion of the Board, underlies the location of the incentive exploratory well.

If (I) above applies and neither (II) nor (III) apply, the Class A interval shall be determined from ground level to the total depth of the incentive exploratory well.

The Class A interval of an incentive exploratory well, the drilling or deepening of which commences on or after November 1, 1983, is the interval of the well that

(a) is not duplicated by a pre-existing well within 2.4 kilometres of the incentive exploratory well, and

(b) if a pre-existing well located less than 4.8 kilometres from the incentive exploratory well has penetrated a significant occurrence of crude oil or gas, occurs more than 150 metres below the base of the deepest significant occurrence of crude oil or gas that, in the opinion of the Board, has been penetrated by that pre-existing well.

	Basis for Credit, Plains Area		*Basis for Credit, Central Area*		*Basis for Credit, Northern and Foothills Areas*	
Depth, Metres	*Cumulative Dollars*	*Incremental $/Metre*	*Cumulative Dollars*	*Incremental $/Metre*	*Cumulative Dollars*	*Incremental $/Metre*
0	0		0		0	
		10		12		22
300	3 000		3 600		6 600	
		22		27		44
600	9 600		11 700		19 800	
		40		47		66
900	21 600		25 800		39 600	
		85		90		115
1 200	47 100		52 800		74 100	
		110		130		133
1 500	80 100		91 800		114 000	
		140		150		158
1 800	122 100		136 800		161 400	
		177		177		190

(continued on next page)

TABLE 3 (continued)

Depth, Metres	Basis for Credit Plains Area		Basis for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
	Cumulative Dollars	Incremental $/Metre	Cumulative Dollars	Incremental $/Metre	Cumulative Dollars	Incremental $/Metre
2 100	175 200		189 900		218 400	
		210		240		267
2 400	238 200		261 900		298 500	
		267		280		493
2 700	318 300		345 900		446 400	
		303		347		667
3 000	409 200		450 000		646 500	
		363		387		800
3 300	518 100		566 100		886 500	
		397		440		867
3 600	637 200		698 100		1 146 600	
		467		520		910
3 900	777 300		854 100		1 419 600	
		523		573		933
4 200	934 200		1 026 000		1 699 500	
		583		667		980
4 500	1 109 100		1 226 100		1 993 500	
		643		733		1 000
4 800	1 302 000		1 446 000		2 293 500	
		757		800		1 133
5 100	1 529 100		1 686 000		2 633 400	
		877		1 000		1 163
5 400	1 792 200		1 986 000		2 982 300	
		933		1 067		1 200
5 700	2 072 100		2 306 100		3 342 300	
		1 167		1 200		1 267
6 000	2 422 200		2 666 100		3 722 400	
		1 200		1 250		1 300

TABLE 4

SCHEDULE O OF THE EXPLORATORY DRILLING INCENTIVE REGULATION, 1983, CLASS B INTERVAL

The Class B interval of an incentive exploratory well, the drilling or deepening of which commences on or after May 1, 1983, and before November 1, 1983, shall be determined by the Board as the interval that

(I) has been duplicated by a pre-existing well within 2.4 kilometres of the incentive exploratory well, **[CASE 2, 3, 5 and 6 in Figure 17]**

(II) occurs more than 150 metres below the base of the deepest significant occurrence of crude oil or gas that, in the opinion of the Board, has been penetrated by a pre-existing well within 4.8 kilometres of the incentive exploratory well, and **[CASE 5 and 6 in Figure 17]**

(III) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that, in the opinion of the Board, underlies the location of the incentive exploratory well.

If (I) above applies and neither (II) nor (III) apply, the Class B interval shall be determined from ground level to the total depth of the incentive exploratory well.

The Class B interval of an incentive exploratory well, the drilling or deepening of which commences on or after November 1, 1983, is the interval of the well that

(a) is duplicated by a pre-existing well within 2.4 kilometres of the incentive exploratory well, and

(b) if a pre-existing well located less than 4.8 kilometres from the incentive exploratory well has penetrated a significant occurrence of crude oil or gas, occurs more than 150 metres below the base of the deepest significant occurrence of crude oil or gas that, in the opinion of the Board, has been penetrated by that pre-existing well.

	Basis for Credit, Plains Area		*Basis for Credit, Central Area*		*Basis for Credit, Northern and Foothills Areas*	
Depth, Metres	*Cumulative Dollars*	*Incremental $/Metre*	*Cumulative Dollars*	*Incremental $/Metre*	*Cumulative Dollars*	*Incremental $/Metre*
0	0	7	0	10	0	16
300	2 100	16	3 000	22	4 800	33
600	6 900	30	9 600	32	14 700	50
900	15 900	65	19 200	69	29 700	86
1 200	35 400	83	39 900	98	55 500	100
1 500	60 300	105	69 300	113	85 500	118
1 800	91 800	133	103 200	133	120 900	143
2 100	131 700	158	143 100	180	163 800	200

(continued on next page)

TABLE 4 (continued)

Depth, Metres	Basis for Credit, Plains Area		Basis for Credit, Central Area		Basis for Credit, Northern and Foothills Areas	
	Cumulative Dollars	Incremental $/Metre	Cumulative Dollars	Incremental $/Metre	Cumulative Dollars	Incremental $/Metre
2 400	179 100		197 100		223 800	
		200		210		370
2 700	239 100		260 100		334 800	
		228		260		500
3 000	307 500		338 100		484 800	
		273		290		600
3 300	389 400		425 100		664 800	
		298		330		650
3 600	478 800		524 100		859 800	
		350		390		683
3 900	583 800		641 100		1 064 700	
		393		430		700
4 200	701 700		770 100		1 274 700	
		438		500		735
4 500	833 100		920 100		1 495 200	
		483		550		750
4 800	978 000		1 085 100		1 720 200	
		568		600		850
5 100	1 148 400		1 265 100		1 975 200	
		658		750		873
5 400	1 345 800		1 490 100		2 237 100	
		700		800		900
5 700	1 555 800		1 730 100		2 507 100	
		875		900		950
6 000	1 818 300		2 000 100		2 792 100	
		900		938		975

Figure 16. Exploratory drilling incentive credit areas

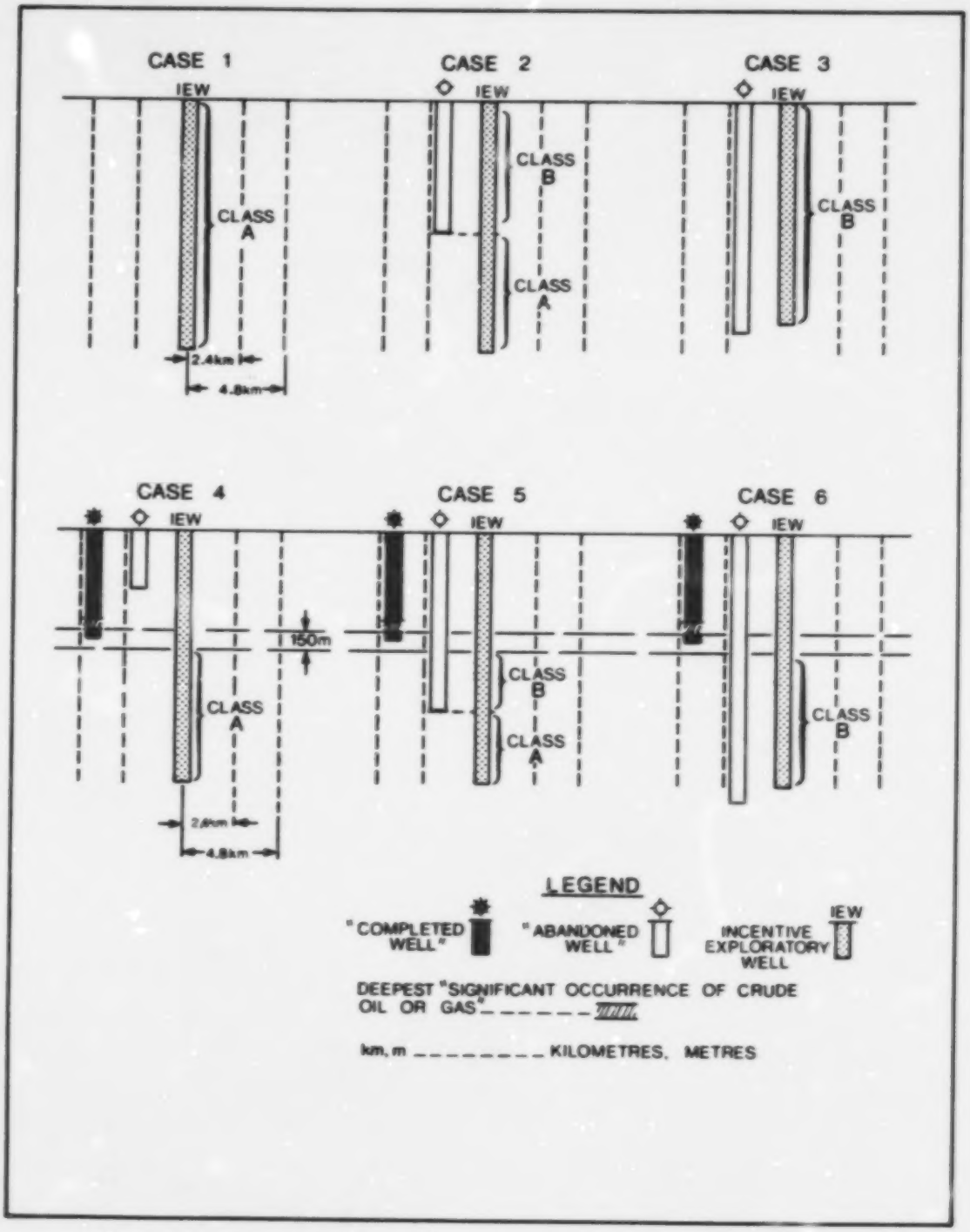


Figure 17. Determination of Class A and Class B intervals under the 1983 Drilling Incentive Regulation

Source: ERCB Information Letter IL 83-9

Credits established under the EDIS may be allocated to participants in the well and can be used to satisfy monies payable to the Crown. The monies may include acquisition fees and bonuses, rentals on petroleum and/or natural gas agreements, gas royalties and taxes on petroleum or natural gas levied under the Freehold Mineral Taxation Act. In 1983, amendments to the regulations were introduced so the money equivalent of the credit established may be paid directly to the licensee of the incentive well.

[24] Royalty exemptions, when oil and/or gas is discovered by incentive exploration wells, are the second incentive under EDIS. On crude oil discoveries, Crown royalties are waived for the initial 60 months of allowable production granted to the incentive exploration well by the ERCB. Royalty exemptions on natural gas vary from 12 to 36 months as follows:

Royalty Exemption Period in Months	Well Spudded On or After	Well Spudded Before
12	April 1, 1981	April 1, 1982
36	April 1, 1982	January 1, 1983
24	January 1, 1983	December 31, 1983
12	December 31, 1983	April 1, 1984

The criterion for determining whether the production from an incentive exploratory well qualifies for royalty exemption is whether the discovered oil and/or gas is from a pool in which no other well within 4.8 kilometres has received royalty exemption.

5.2 GEOPHYSICAL INCENTIVE SYSTEM

[25] The Geophysical Incentive System (GIS) program, implemented in January, 1975, was primarily designed to stimulate geophysical activity in the province. It was originally intended as a short-term program

terminating in 1978, but subsequent regulations have extended the program to March 31, 1984. The program grants credit or cash to any company holding an exploration licence in the province; this may include any oil company or owners of geophysical equipment who have a permit to operate in the province.

In order to qualify for credit or cash the geophysical program must:

a) Evaluate Alberta Crown oil and gas mineral rights;
b) Obtain from the program the required sub-surface coverage;
c) Obtain state-of-the-art geophysical data;
d) Conduct field work in a satisfactory manner.

Credits are earned in accordance with Schedule B of the 1983 Geophysical Incentive Regulations (Table 5). The rates are established according to the cost of conducting programs in various geographic areas of the province and the type of equipment used. The province is divided into four geographic areas: the Foothills, the Green, the
[26] Yellow and the Plains areas (Figure 18). The credit rates per kilometre for each area take into account the terrain, accessibility constraints and type of equipment used.

Geophysical incentive credits established under the program may be used to satisfy monies payable to the Crown as outlined in Section 5.1. As an option in the 1983 regulations, the licensee may obtain the established credit in cash.

Within 150 days of completing the field-recording portion of a program, the licensee must file an application for geophysical incentive credits. The application must be accompanied by:

1. A final report on the geophysical program;

TABLE 5

SCHEDULE B OF THE GEOPHYSICAL INCENTIVE REGULATION, 1981

Part I
(Section 9)

DETERMINATION OF CREDIT

The credit in dollars for a geophysical incentive program shall be calculated in accordance with the following table:

Area of Province	Geophysical Incentive Programs using special recording methods and approved foothills programs	Geophysical Incentive Programs Other than programs described in Column A
	$/Km of Minimum Subsurface Coverage	$/Km of Minimum Subsurface Coverage
Yellow Area or Plains Area	700-5000	700
Green Area		
Existing secondary roads, forestry roads or other roads	700-5000	700
Existing cut lines or new cut lines		
Wheeled exploration equipment	1000-5000	1000
Tracked exploration equipment	1700-5000	1700
Portable exploration equipment	3000-5000	3000
Foothills Area		
Wheeled exploration equipment	1000-5000	Nil
Tracked exploration equipment	1700-5000	Nil
Portable exploration equipment	3000-5000	Nil

Part II

ACQUISITION COST

The cost of acquiring geophysical information and data under section 14(2) to a person requesting that information and data shall be, in respect of each kilometre of geophysical information and data requested, not more than 50% of the incentive credit actually determined and paid for that kilometre of data or, if no determination or payment has been made, not more than 50% of the incentive credit for an equivalent kilometre of minimum subsurface coverage, calculated in accordance with Part I of this Schedule.

Figure 18. Geophysical incentive program areas of the province

2. A computer stack summary or stacking diagram;[8]
3. Maps showing the location of lines and actual shot points;
4. Any other specific information requested by the Exploration Branch.

The application must also indicate whether the licensee is applying for cash or credit and the manner of allocation of that credit among participants in the program. [27]

The seismic licensee may hold all incentive data in confidence for five years. This is called the confidentiality period. The licensee is required after the confidentiality period to make the data available to requesting parties for five years. In the 1983 Geophysical Incentive Regulations, the incentive seismic licensee, when selling the data after the confidentiality period, is not allowed to charge in excess of 200 per cent of the incentive credit amount received from the department for that particular kilometre of data. There are no price restrictions on incentive data which a licensee may elect to sell during the confidentiality period.

[8] A computer print-out indicating the number of times a subsurface point has been sampled (e.g., 10CDP).

6. REFERENCES TO EFFECTIVE LEGISLATION AS OF DECEMBER, 1983

Citation		Page
[1]	Natural Gas Licence Regulations, 1962, A.R. 242/79 . . .	8
[2]	Mines and Minerals Act, S.A. 1981, cB-15, A.R. 272/82 (referred to hereafter as Mines and Minerals Act), Parts 1 and 5	17
[3]	Mines and Minerals Act, Part 5, section 96	22
[4]	Mines and Minerals Act, Part 5, section 106, and Petroleum and Natural Gas Licence Regulations, A.R. 248/79	22
[5]	Petroleum and Natural Gas Licence Regulations, A.R. 248/79, section 13(3) and (4)	23
[6]	Mines and Minerals Act, Part 5, Petroleum and Natural Gas Lease Regulations, A.R. 318/81	26
[7]	Petroleum and Natural Gas Lease Regulations, A.R. 318/81, section 6	29
[8]	Mines and Minerals Act, Part 5, section 103	32
[9]	Mines and Minerals Act, Part 5, section 99(1)(a) . . .	32
[10]	Mines and Minerals Act, Part 5, sections 99(1)(b) and (c)	32
[11]	Mines and Minerals Act, Part 5, section 102(3)	34
[12]	Mines and Minerals Act, Part 5, section 102(4)	34
[13]	Mines and Minerals Act, Part 5, section 100	37
[14]	Mines and Minerals Act, Part 5, section 104	37
[15]	Mines and Minerals Act, Part 5, section 103.1	41
[16]	Petroleum and Natural Gas Lease Regulations, A.R. 318/81, sections 12 through 17 inclusive	41
[17]	Mines and Minerals Act, Part 9	44
[18]	Exploration Regulation, A.R. 40/82	47
[19]	Exploration Regulation, A.R. 40/82, sections 10 and 11 .	49

Citation		Page
[20]	Exploration Regulation, A.R. 40/82, section 47	50
[21]	Exploration Regulation, A.R. 40/82, sections 7 and 8	50
[22]	Exploration Drilling Incentive Regulation, 1978, A.R. 471/82	51
[23]	Exploration Drilling Incentive Regulation, 1978, A.R. 471/82	52
[24]	Exploration Drilling Incentive Regulation, 1978, A.R. 471/82, sections 15 and 16	59
[25]	Geophysical Incentive Regulation, 1981, A.R. 90/83 . .	59
[26]	Geophysical Incentive Regulation, 1981, A.R. 90/83, section 13	60
[27]	Geophysical Incentive Regulation, 1981, A.R. 90/83, section 14	63